AR82

2006 ANNUAL REPORT

MASTERS ENERGY INC.

EXPERIENCE, FOCUS, BALANCE.



Masters Energy Inc. is an Alberta-based corporation engaged in the acquisition, exploration and development of petroleum and natural gas reserves in western Canada. Masters' common shares are listed on the Toronto Stock Exchange under the trading symbol "MSY".

ABBREVIATIONS

Oil and natural gas liquids

mm	million
bbl	barrel
bbls	barrels
mbbls	thousand barrels
mmbbls	million barrels
bbls/d	barrels per day
boe/d	barrels of oil equivalent per day
mboe	thousand barrels of oil equivalent
NGL	natural gas liquids

Natural gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
GJ	gigajoule

Other

AECO	EnCana Corporation natural gas storage facility located at Suffield, Alberta
°API	Specific gravity of crude oil measured on the American Petroleum Institute gravity scale (28° API or higher is generally referred to as light crude oil)
ARTC	Alberta Royalty Tax Credit
boe	Barrel of oil equivalent of crude oil and natural gas on the basis of 1 bbl equals 6 mcf of natural gas
US	United States
WTI	West Texas Intermediate, the reference price paid in US dollars at Cushing, Oklahoma for crude oil of 40°API

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ADVISORIES

The calculations of barrels of oil equivalent ("boe") are based on a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil. A boe unit may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf=1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

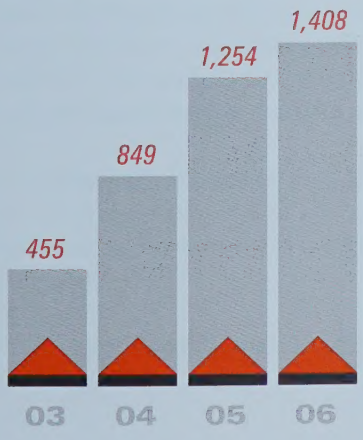
Certain information regarding the Company, including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of commodity prices, currency fluctuations, uncertainties of reserves estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated. Masters assumes no obligation to update the forward-looking statements contained herein or to update the reasons why actual results could differ from those contemplated by the forward-looking statements, unless so required by applicable securities law.

HIGHLIGHTS

Years ended December 31	2006	2005
Financial *($ thousands, except per share amounts)*		
Gross revenue	**24,264**	22,929
Funds generated by operations	**11,439**	12,159
Per share - basic	**0.75**	0.84
- diluted	**0.72**	0.81
Net earnings	**1,858**	3,611
Per share - basic	**0.12**	0.25
- diluted	**0.12**	0.24
Capital expenditures, net	**18,289**	27,533
Working capital deficit	**2,156**	5,013
Long-term debt	**17,824**	14,093
Operations		
Production		
Crude oil *(bbls/d)*	**784**	697
NGL *(bbls/d)*	**10**	11
Natural gas *(mcf/d)*	**3,685**	3,276
Total production *(boe/d at 6:1)*	**1,408**	1,254
Average sales price		
Crude oil *($/bbl)*	**49.99**	44.82
NGL *($/bbl)*	**63.33**	55.19
Natural gas *($/mcf)*	**6.59**	8.87

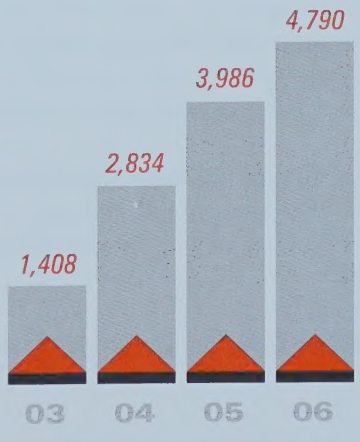
masters' growth

(boe/d at 6:1)



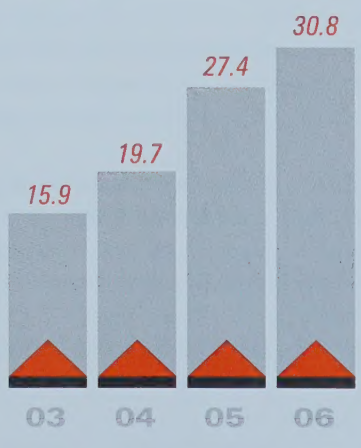
DAILY PRODUCTION

(mboe)



PROVED + PROBABLE RESERVES

(boe/100 shares)



RESERVES PER SHARE

PRESIDENT'S MESSAGE TO SHAREHOLDERS

Masters Energy Inc. ("Masters") progressed steadily toward our long-term goals during 2006 by performing well in a number of aspects of our business. Building on our momentum from the previous year, we maintained an impressive level of activity. We drilled 31 wells, acquired in excess of 11,000 net acres of undeveloped land and completed extensive 2D and 3D seismic programs in Masters' core areas. Our investments in undeveloped land and seismic provided Masters with a sizeable inventory of exploration and development prospects which created opportunities to add value in 2006.

STRATEGY FOR 2006

- Continue exploiting our large undeveloped land base
- Build value within our core areas at Little Bow and North Peace River Arch
- Pursue high impact exploration plays in regions outside our core areas
- Maintain a strong balance sheet while utilizing our debt capacity for strategic acquisition opportunities
- Enhance shareholder value

PROGRESS IN 2006

I am pleased to report to our shareholders that Masters made considerable progress toward these objectives.

- We exploited our undeveloped land base by drilling 31 wells with a 55 percent success ratio.
- The value of our Little Bow and North Peace River Arch properties increased 12 percent as a result of drilling 16 natural gas wells and recompleting several existing oil wells. Total proved plus probable reserves increased 20 percent.
- We maintained a strong balance sheet with the $6.2 million sale of non-core oil and natural gas interests, which had no impact on Masters' production volumes or gross reserves. We also raised equity through a private placement of 1,000,000 flow-through common shares for proceeds of $6.1million.
- Masters' asset base grew in 2006 as we:

 - increased annual production by 12 percent to 1,408 boe per day from 1,254 boe per day;

 - replaced our annual production by 2.6 times (on proved plus probable reserves additions and revisions); and

 - increased total proved plus probable reserves 20 percent with the addition of 1.3 million boe of proved plus probable reserves.

- We enhanced value for our shareholders by:

 - adding proved plus probable reserves at $14.32 per boe in finding, development and net acquisition costs, inclusive of future capital costs;

 - investing capital efficiently, achieving a recycle ratio of 1.9; and

 - increasing Masters' reserves per 100 shares ratio by 12 percent to 30.8 boe.

PRESIDENT'S MESSAGE TO SHAREHOLDERS

PRODUCTION GROWTH

Although Masters performed well in 2006, we were disappointed with the increase in average daily production volumes for the year. Average daily production increased 12 percent to 1,408 boe per day. The majority of the new natural gas wells were not tied-in until the fourth quarter, much later than originally anticipated. Production for the fourth quarter of 2006 averaged 1,495 boe per day. By year-end, production had climbed to 1,600 boe per day. We expect several tie-in projects in the North Peace River Arch area which encountered delays in the last quarter of 2006 will be completed before spring break-up in 2007.

INDUSTRY CONDITIONS

The oil and natural gas industry experienced some significant challenges during 2006. The robust activity levels at the beginning of 2006 created cost pressures that impacted capital spending and operating expenses. Commodity prices fluctuated significantly with Bow River medium quality crude prices ranging from $34.27 to $66.08 per barrel and natural gas monthly spot prices ranging from $4.54 to $8.43 per thousand cubic feet. In addition, the federal government's October 31, 2006 announcement to tax trusts created a great deal of uncertainty within the capital markets not only for energy trusts but also for exploration and production companies. Throughout this challenging year Masters persistently stayed focused on its objectives.

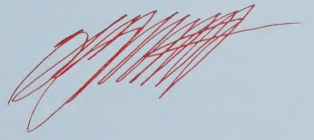
OUTLOOK FOR 2007

Masters' strategy is to continue to exploit our large undeveloped land base, build value within our core producing areas, continue to expand our prospect inventory and pursue several high impact exploration plays in regions outside of our core areas. Plans are to spend $20 million in exploration and development projects emphasizing natural gas prospects. We anticipate this level of capital will allow us to drill 25 - 30 wells. We expect opportunities for acquisitions will be available. Masters will maintain our strategy of pursuing acquisitions that fit strategically and have the potential to add shareholder value.

The current business environment for the oil and natural gas sector remains attractive. Commodity prices are relatively strong, interest rates remain low, demand for energy is high and reasonable access to capital markets underpins the current strong business environment in our sector. Demand for oilfield services and supplies and delays with respect to implementing field work appear to be coming off the peak of late 2005 and early 2006 and are returning to historical levels of activity and timing. We will respond to this by endeavouring to capture Masters' opportunities in a more cost effective and timely manner.

Masters is fortunate to employ a team of experienced, knowledgeable and talented people. The combination of our committed team, significant investment opportunities, solid foundation of properties and attractive business fundamentals in the oil and natural gas sector creates our strong sense of optimism for the future. I am not only excited by the exploitation opportunities available to Masters in our core areas but also believe in the upside potential which exists in our inventory of high impact exploration prospects.

In summary, Masters has accomplished growth for our shareholders since commencing operations. Our successful growth is the result of the solid and collective effort from experienced employees and the support of our Board of Directors. On behalf of management, I extend my thanks to all members of Masters' team and to every stakeholder for their significant contribution during 2006.



Geoffrey C. Merritt
President and Chief Executive Officer
March 9, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORIES

Management's discussion and analysis ("MD&A") of Masters Energy Inc. ("Masters", the "company", "we" or "our"), provided as of March 9, 2007, should be read in conjunction with the audited financial statements and related notes for the years ended December 31, 2006 and 2005.

Basis of presentation - The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Non-GAAP measurements - The MD&A contains the term 'funds generated by operations' and 'funds generated by operations per share', which should not be considered an alternative to, or more meaningful than, net earnings or cash flow from operating activities as determined in accordance with GAAP as an indicator of the company's performance. Masters' determination of funds generated by operations or funds generated by operations per share may not be comparable to that reported by other companies. Management uses funds generated by operations to analyze operating performance and leverage and considers funds generated by operations to be a key measure as it demonstrates the company's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between net earnings and funds generated by operations can be found in the statements of cash flows in the audited financial statements. Masters presents funds generated by operations per share, which is prohibited under GAAP. Per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Masters uses certain industry benchmarks such as operating netback and net asset value to analyze financial and operating performance. These benchmarks as presented do not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

Presentation of boe - Masters bases calculations of barrels of oil equivalent ("boe") on a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil. The boe unit may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf equals 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Forward-looking information - This MD&A contains forward-looking or outlook information with regard to Masters within the meaning of applicable securities laws. Forward-looking statements may include estimates, plans, expectation, forecasts, guidance or other statements that are not statements of fact. Masters believes the expectations reflected in such forward-looking statements are reasonable. However, no assurance can be given that such expectations will prove to be correct. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward looking statements. These risks include but are not limited to: crude oil and natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, Masters' ability to replace and expand oil and natural gas reserves, the sources and adequacy of funding for capital investments, the company's future growth prospects and current and expected financial requirements, the cost of future reclamation and site restoration, Masters' ability to enter into or renew leases and to secure adequate product transportation, changes in environmental and other regulations and general economic conditions. These statements speak only as of the date of this MD&A and Masters does not undertake an obligation to update our forward-looking statements except as required by law.

MANAGEMENT'S DISCUSSION AND ANALYSIS

CORPORATE OVERVIEW

Masters Energy Inc. was incorporated under the Alberta Business Corporations Act on August 28, 2003. During the fall of 2003 Masters completed a private placement of 17,752,000 special warrants for gross proceeds of $17.8 million. On December 22, 2003 Masters closed the acquisition of producing oil and gas properties in the Little Bow area of southern Alberta. At the time of acquiring the property, daily production was approximately 450 boe/d comprised of 90 percent oil and 10 percent gas.

On February 26, 2004, Masters and Terraquest, a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. The transaction saw Terraquest shareholders receive one Amalco common share for every 12 common shares of Terraquest and Masters shareholders received one Amalco common share for every two common shares of Masters. After giving effect to the transaction, Amalco had approximately 14.4 million common shares outstanding.

During 2005, Masters acquired oil and natural gas producing properties in the North Peace River Arch area for $7.8 million. At the time of the acquisitions the properties produced approximately 160 boe/d and provided ownership in one natural gas processing plant, five compressor stations and associated infrastructure.

During April 2006, Masters issued 1,000,000 common shares, on a flow-through basis, for total proceeds of $6.1 million. During the month of September 2006, Masters sold non-core properties for total proceeds of $6.2 million before final adjustments.

In 2006, Masters drilled 31 exploration and development wells, resulting in 17 natural gas wells for an overall success rate of 55 percent. During 2006, we spent $24.5 million, before the sale of non-core property proceeds, on our exploration and development program.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2006 AND 2005

PRODUCTION

	2006	2005
Annual production		
Crude oil *(bbls)*	**286,058**	254,450
Natural gas liquids ("NGL") *(bbls)*	**3,773**	3,838
Natural gas *(mcf)*	**1,345,114**	1,195,641
Total *(boe)*	**514,017**	457,562
Daily production		
Crude oil *(bbls/d)*	**784**	697
NGL *(bbls/d)*	**10**	11
Natural gas *(mcf/d)*	**3,685**	3,276
Total *(boe/d)*	**1,408**	1,254

For the year ended December 31, 2006, total production increased 12 percent and averaged 1,408 boe/d (2005 - 1,254 boe/d) with oil production, including NGL, comprising 56 percent (2005 - 56 percent) and natural gas, 44 percent (2005 - 44 percent). Production increased during 2006 as a result of drilling and tying-in successful wells.

Based on drilling activity budgeted for 2007 and production expected from existing producing properties, Masters forecasts an average production rate of 1,800 - 2,000 boe/d comprised of 45 percent oil including NGL and 55 percent natural gas.

PRICES

	2006	2005
Crude oil *($/bbl)*	**49.99**	44.82
NGL *($/bbl)*	**63.33**	55.19
Natural gas *($/mcf)*	**6.59**	8.87

West Texas Intermediate ("WTI") is the benchmark for North American oil prices and is the crude oil type against which NYMEX futures contracts are priced. Canadian crude oil prices are based on refiners' postings at hubs such as Edmonton and Hardisty, Alberta. The basis for Canadian postings is the WTI price at Cushing, Oklahoma minus a transportation differential, adjusted for the US/Canadian currency exchange rate and for relative quality and regional market conditions.

During 2006, North America experienced historically high price levels for WTI crude oil due to concerns regarding supply. As a result, the average price for a barrel of WTI crude during 2006 increased US$9.50 to US$66.09. During 2006, the Canadian dollar strengthened relative to the US dollar with the average currency exchange rate for $1.00 Canadian increasing to US$0.88 (2005 - US$0.83). The higher exchange rate reduced the price received for delivery of crude within Canadian markets. The narrowing quality price differential postings on medium types of crude oil had a positive effect during 2006. The average differential between Edmonton light sweet crude postings and Hardisty Bow River medium crude decreased to approximately $22.00 per bbl (2005 - $25.00 per bbl).

In 2006, Masters' average field price for crude oil was $49.99 (2005 - $44.82) per bbl versus $73.25 (2005 - $69.18) per bbl for light sweet postings at Edmonton, Alberta. All crude revenues during 2006 were from sales to spot markets. Masters did not hedge any production during 2006. Masters' 2006 crude oil production was 84 percent medium and 16 percent lighter gravity crude.

The typical reference for US natural gas prices is NYMEX at Henry Hub, Louisiana while the reference for Canadian prices is at Nova Inventory Transfer ("NIT") or the AECO Hub. Masters sold all natural gas produced during 2006 and 2005 to the spot market according to the AECO reference price. Masters did not enter into any fixed or hedged type natural gas sales contracts during 2006 and 2005.

During the early portion of 2006, North America experienced some of the warmest weather on record causing the demand for natural gas to be down from historic winter levels. This resulted in record levels for natural gas supply in storage in the United States and Canada at the end of the withdrawal season. Storage levels at the end of the first quarter of 2006 were approximately 60 percent above the five-year averages. As a result of this large storage overhang, 2006 natural gas prices were weaker than the previous year.

Masters' average natural gas price in 2006 was $6.59 (2005 - $8.87) per mcf versus $6.38 (2005 - $8.69) per mcf for spot postings of the AECO reference price.

Masters' management complies with a Risk Management Policy approved by the board of directors. The objective of Masters' risk management activities is to reduce exposure to decreases in commodity prices that would materially impact funds generated by operating activities and, ultimately, reduce capital spending which generates Masters' growth. Any transactions entered would involve credit worthy purchasers and would be for less than one year. To ensure Masters has sufficient physical volumes available to meet the obligations of such transactions, Masters limits the volumes contracted to no more than 50 percent of forecasted production after royalties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For 2007 Masters has entered into a fixed natural gas hedge as follows which was outstanding at December 31, 2006.

Product	Index	Term	Daily notional volume	Price received
Gas fixed	AECO-C	Apr. 1/07 - Oct. 31/07	1,500 GJ	$7.54 per GJ

The forecasted commodity prices used for Masters' 2007 budget were Cdn$72.00 (US$61.00 WTI) per bbl of Edmonton light quality crude oil and Cdn$7.80 per GJ ($8.25 per mcf) for natural gas at AECO. Masters' 2007 budget uses a forecasted foreign currency exchange rate estimated to average US$0.85 per Cdn$1.00.

REVENUES

($ thousands, except as indicated)	2006	2005
Crude oil revenue	**14,299**	11,405
NGL revenue	**239**	211
Natural gas revenue	**8,867**	10,600
Total petroleum and natural gas revenue	**23,405**	22,216
Royalty and other revenue	**859**	713
Total revenue	**24,264**	22,929
Total petroleum and natural gas revenue per boe *($)*	**45.53**	48.55
Total revenue per boe *($)*	**47.21**	50.11

Petroleum and natural gas revenue for the 2006 year increased five percent to $23.4 million due to a 12 percent increase in production offset by a six percent decrease in realized commodity prices.

Royalty and other revenue increased by 20 percent to $0.9 million as a result of royalty interests receiving higher crude commodity prices throughout 2006.

Based on forecasted production volumes and commodity prices, Masters forecasts an increase in oil and natural gas revenues of approximately 45 - 55 percent during 2007.

ROYALTIES

($ thousands, except as indicated)	2006	2005
Crown	**4,296**	4,382
Alberta Royalty Tax Credit ("ARTC")	**(411)**	(500)
Crown, net of ARTC	**3,885**	3,882
Freehold and gross overriding	**509**	813
Total royalties	**4,394**	4,695
Per boe *($)*	**8.55**	10.26
Average royalty rate *(%)*[1]	**18.8**	21.1

(1) A percentage of total petroleum and natural gas revenue.

Royalties paid for the year ended December 31, 2006 decreased nine percent as a result of lower crown rates on natural gas sales and lower freehold and gross overriding royalties paid to third parties. Masters' average royalty rate decreased to 18.8 percent during 2006 (2005 - 21.1 percent). The 2006 royalty expense is comprised of 90 percent (2005 - 83 percent) paid to the crown with the remainder paid to freehold and gross overriding royalty owners. In 2006, Masters paid royalties amounting to $8.55 per boe (2005 - $10.26 per boe).

During the third quarter of 2006, the Alberta provincial government announced termination of the ARTC program at the end of the 2006 year. Masters anticipates forecasted royalty rates for 2007 will be moderately higher than our historical rates.

UNREALIZED GAIN ON COMMODITY CONTRACT

For 2007 Masters has entered into a fixed natural gas hedge as follows.

Product	Index	Term	Daily notional volume	Price received
Gas fixed	AECO-C	Apr. 1/07 - Oct. 31/07	1,500 GJ	$7.54 per GJ

An unrealized gain of $0.3 million on the commodity contract represents the fair value of the contract at December 31, 2006.

OPERATING EXPENSES

($ thousands, except as indicated)	2006	2005
Total operating expenses	**5,600**	4,168
Per boe *($)*	**10.89**	9.11

In 2006, operating expenses per boe increased 20 percent to $10.89 per boe. Operating expenses were higher due to an adjustment in third party processing fees, increased electrical power rates, well maintenance and liquids transportation.

Masters expects 2007 operating expenses per boe to decrease as production volumes increase and fixed costs are spread over a larger production base from our core areas. However, we anticipate that any increased industry activity may result in variable costs, such as utility and service fees, partially offsetting the decrease in fixed operating expenses per boe.

Netback analysis

($ per boe)	2006	2005
Oil and natural gas revenues	**45.53**	48.55
Royalty and other revenue	**1.68**	1.56
	47.21	50.11
Royalty expense, net of ARTC	**(8.55)**	(10.26)
Operating expenses	**(10.89)**	(9.11)
Operating netback	**27.77**	30.74

GENERAL AND ADMINISTRATIVE

($ thousands, except as indicated)	2006	2005
Gross general and administrative	**2,594**	1,904
Operating recoveries	**(114)**	(78)
Capitalized expenses	**(813)**	(617)
General and administrative expense, before stock-based compensation	**1,667**	1,209
Future stock-based compensation	**533**	227
Capitalized future stock-based compensation	**(211)**	-
Net stock-based compensation expense	**322**	227
Total general and administrative expense	**1,989**	1,436
General and administrative expense, before stock-based compensation, per boe *($)*	**3.24**	2.64
Total general and administrative expense per boe *($)*	**3.87**	3.14

MANAGEMENT'S DISCUSSION AND ANALYSIS

On a per boe basis, total general and administrative expense in 2006 increased 23 percent to $3.87 per boe (2005 - $3.14 per boe). The 36 percent increase in gross general and administrative expenses 2006 to $2.6 million (2005 - $1.9 million), resulted mainly from increased temporary consultant fees, professional fees and results-based compensation. During 2006, Masters capitalized approximately one-third of general and administrative costs associated with exploration and development activities. Masters capitalizes general and administrative expense directly related to exploration and development activities as these costs are associated with adding reserves. General and administrative expenses for 2006 include a non-cash provision of $0.3 million (2005 - $0.2 million) for the net future stock-based compensation.

We anticipate that total general and administrative expenses for 2007 will be similar to 2006. Based on forecasted production and capital spending, we estimate 2007 staff levels will be similar to 2006. As we bring new production on-stream, we anticipate a reduction in general and administrative costs per boe.

INTEREST EXPENSE

($ thousands, except as indicated)	2006	2005
Total interest expense	**1,014**	414
Per boe *($)*	**1.97**	0.91

Interest expense increased 145 percent to $1.0 million in 2006 (2005 - $0.4 million). This reflects an increase in average debt levels during the year as interest rates remained relatively stable. At year-end 2006, Masters had bank debt of $17.8 million (2005 - $14.1 million). Average debt outstanding during the year was approximately $17.6 million. Increased exploration and development activities during the first half of 2006 led to an increase in the year-end balance from the average annual borrowing level. Our average interest rate to borrow during the year was 5.75 percent.

Masters forecasts average bank debt and interest rates for 2007 to be approximately the same as 2006. For 2007, we anticipate that Masters' ratio of net debt to funds generated by operations will be approximately in the range of 1.0 - 1.1 to one.

DEPLETION, DEPRECIATION AND ACCRETION

($ thousands, except as indicated)	2006	2005
Depletion	**9,260**	6,502
Depreciation	**10**	11
Accretion on asset retirement obligations	**130**	114
Total depletion, depreciation and accretion expense	**9,400**	6,627
Depletion, depreciation and accretion expense per boe *($)*	**18.29**	14.48

During 2006, depletion, depreciation and accretion expense increased 42 percent to $9.4 million (2005 - $6.6 million). This increase is the result of Masters' increase in production and cost for reserves additions. Depletion, depreciation and accretion increased 26 percent to $18.29 per boe during 2006 (2005 - $14.48 per boe) as a result of 2006 finding and development costs attributed to proved reserves additions being comparable to the historical carrying values of assets eligible for depletion.

Masters performs an annual and quarterly ceiling test in accordance with the Canadian Institute Chartered Accountants' full cost accounting guidelines, using forecasted prices determined by the independent qualified reserves evaluator who evaluates Masters' reserves. At December 31, 2006, the impairment recognition portion of the ceiling test indicated the estimated undiscounted future cash flows from proved reserves exceeded the carrying values of producing petroleum and natural gas properties and, therefore, a ceiling test adjustment was not required.

MANAGEMENT'S DISCUSSION AND ANALYSIS

INCOME TAXES

ept as indicated)	2006	2005
ture	334	1,975
ital	-	3
l income taxes	334	1,978
ective tax rate (%)	18.0	35.4

future and capital, decreased 86 percent in 2006 to $0.3 million (2005 - $2.0 million). The decrease in 2006 future is due to lower earnings before taxes and a reduction in the federal and provincial income tax rates that were enacted during 2006. Based on available tax pools, forecasted capital spending levels and commodity prices, ters does not expect to be currently taxable for the 2007 year.

pproximately $49.0 million in tax pools, reduced by $5.3 million of 2006 flow-through expenditures that were February 2007, to shelter taxable income in future years.

below shows estimated 2006 tax pools.

	2006
Exploration Expense	8,083
Development Expense	8,485
n Oil and Gas Property Expense	14,186
ited Capital Cost	17,425
	774
	48,953

NET EARNINGS

nings decreased 45 percent to $1.9 million (2005 - $3.6 million), primarily from increased depletion, depreciation expense. Net earnings decreased in 2006 to $3.61 per boe (2005 - $7.89 per boe) while funds generated by ting activities decreased in 2006 to $22.56 per boe (2005 - $27.19 per boe).

Earnings ratios

pt as indicated)	2006	2005
nings	1,858	3,611
rnings ratios (%)		
Return on capital [1]	4.9	10.1
Return on investment [2]	4.4	9.5
Return on shareholder equity [3]	5.2	12.2

(1) *Net earnings plus after tax financing charges on debt divided by average of opening and closing capital employed. Capital employed is a total of equity and bank debt.*

(2) *Net earnings plus after-tax financing charges on debt divided by average net investment. Net investment is total assets less current liabilities. Return on investment is calculated using the average opening and closing net investment.*

(3) *Net earnings are divided by average of opening and closing shareholders' equity.*

MANAGEMENT'S DISCUSSION AND ANALYSIS

Net earnings per boe

($ per boe)	2006	2005
Total revenues	**47.21**	50.11
Royalties	**(8.55)**	(10.26)
Operating expenses	**(10.89)**	(9.11)
Net operating income	**27.77**	30.74
General and administrative (excluding stock-based compensation expense)	**(3.24)**	(2.64)
Interest expense	**(1.97)**	(0.91)
Funds generated by operating activities	**22.56**	27.19
Depletion, depreciation and accretion	**(18.29)**	(14.48)
Stock-based compensation	**(0.63)**	(0.50)
Taxes and other	**(0.03)**	(4.32)
Net earnings	**3.61**	7.89

SHARE CAPITAL

During 2006, Masters issued 1,046,666 common shares (2005 - 159,666) on a flow-through basis and on the employees exercise of stock options. Stock options and special warrants granted to employees during the year amounted to 469,000 common shares (2005 - 50,000 common shares).

During November 2006, Masters announced a normal course issuer bid which is in effect for one year. At December 31, 2006, Masters had acquired and cancelled 30,000 common shares through the issuer bid process.

The weighted average common shares outstanding, for the three month period ended December 31, 2006 was 15,558,669 basic (15,974,141 - diluted). For the year ended December 31, 2006 the basic weighted average shares outstanding was 15,255,640 (2005 - 14,420,197) and the diluted average shares outstanding was 15,887,870 (2005 - 15,090,130). Common shares issued and outstanding, as at December 31, 2006, were 15,539,979 (2005 - 14,523,313).

As of the date of this MD&A and since the 2006 year-end, an additional 70,000 common shares have been acquired and cancelled through the normal course issuer bid.

Outstanding common shares

(thousands)	2006	2005
Weighted average outstanding common shares		
Basic	**15,256**	14,420
Diluted	**15,888**	15,090
Outstanding common shares at December 31		
Common shares (basic)	**15,540**	14,523
Common share options	**1,451**	1,127
Common share warrants	**885**	870
Common shares outstanding (diluted)	**17,876**	16,520

Per share information

...ls, except as indicated)	2006	2005
Net earnings	1,858	3,611
...earnings per share *($)*		
...Basic	0.12	0.25
...Diluted	0.12	0.24
...ds generated by operations	11,439	12,159
...enerated by operations per share *($)*		
...sic	0.75	0.84
...iluted	0.72	0.81
... book value	70,275	60,016
... book value per share *($)*[1]		
...sic	4.52	4.13
...Diluted	3.93	3.63
...e (shareholders' equity)[1]	39,921	31,791
...e per share *($)*		
...sic	2.57	2.19
...d	2.23	1.92
...s probable reserves *(mboe)*	4,790	3,986
... per 100 shares *(boe)*[1]		
...	30.8	27.4
...luted	26.8	24.1
...oduction *(mboe)*	514	458
... per 100 shares *(boe)*[1]		
...	3.3	3.2
...ted	2.9	2.8

...ted using outstanding common shares, options and warrants at year-end.

...SET VALUE

...net asset value per share at December 31, 2006 decreased by nine percent to $4.44 (2005 - $4.86) per basic share and ...ght percent to $4.28 (2005 - $4.63) per diluted share.

...ars, except as indicated)	2006 constant price	2006 forecast price[1]	2005 forecast price[1]
...d plus probable reserves value (10% discount before tax)	68,917	76,736	74,761
Undeveloped acreage[2]	12,233	12,233	14,965
Net debt	(19,980)	(19,980)	(19,106)
Basic net asset value	61,170	68,989	70,620
Projected proceeds on exercise of options and warrants	7,470	7,470	5,847
Diluted net asset value	68,640	76,459	76,467
Common shares outstanding *(thousands)*			-
Basic	15,540	15,540	14,523
Diluted	17,876	17,876	16,520
Net asset value per common share *($)*			
Basic[3]	3.94	4.44	4.86
Diluted[3]	3.84	4.28	4.63

(1) The reserves values are based on before tax future cash flows as evaluated by the Company's independent qualified reserves evaluators, McDaniel & Associates Consultants Ltd. using their future commodity price forecast, then in effect.
(2) The land values are determined using an estimated value in 2006 of $150 (2005 - $150) per undeveloped acre.
(3) Calculated using outstanding common shares, options and warrants at year-end.

MANAGEMENT'S DISCUSSION AND ANALYSIS

SHARE TRADING ACTIVITY

Masters' common shares are listed and posted for trading on the TSX under the symbol MSY. The following table summarizes monthly trading activity of Masters common shares for the year ended December 31, 2006.

Month	Volume	High	Low	Close
January	705,000	6.75	4.86	5.79
February	497,900	5.61	4.25	4.72
March	554,300	5.15	4.25	4.89
April	286,000	5.39	4.46	5.00
May	305,900	5.04	3.75	4.15
June	212,500	4.40	3.56	3.80
July	163,400	3.81	3.25	3.75
August	154,600	4.28	3.75	3.76
September	455,000	4.25	3.26	3.35
October	262,200	4.08	3.00	4.00
November	296,400	4.07	3.28	3.32
December	306,400	3.59	3.17	3.40

Year ended December 31, 2005

Month	Volume	High	Low	Close
January	315,300	2.68	2.31	2.60
February	2,384,000	3.85	2.60	3.70
March	1,449,500	4.20	3.10	3.40
April	639,000	3.65	3.05	3.41
May	471,700	3.49	3.06	3.40
June	1,985,400	3.80	3.35	3.64
July	826,200	4.09	3.62	3.96
August	1,017,200	4.49	3.83	4.41
September	520,400	4.70	4.31	4.55
October	1,048,400	5.45	4.60	5.15
November	648,100	6.05	5.00	5.60
December	654,800	6.95	5.68	6.47

CAPITAL EXPENDITURES

Total net capital expenditures during 2006, after the disposal of oil and natural gas property interests for proceeds of $6.2 million, were $18.3 million (2005 - $27.5 million). The 2005 expenditures included the $7.8 million for the acquisition of producing oil and natural gas properties in the North Peace River Arch area. The 2006 exploration and development activity resulted in 31 (2005 - 22) gross exploration and development wells drilled, acquisition of 11,683 (2005 - 15,648) net acres of undeveloped crown land, completion of several 3D seismic programs to acquire 150 (2005 - 179) square kilometers of data and over 100 kilometers of 2D seismic data. In 2006, Masters' exploration and development capital allocation was approximately $6.3 (2005 - $12.8) million in southern Alberta and $18.2 (2005 - $7.5) million in northern and central Alberta.

...sands)	2006	2005
...nd	1,669	2,401
...eological and geophysical	3,305	3,037
Drilling and completions	11,892	10,430
...pping and facilities	7,623	4,390
...ther	-	31
Total exploration and development capital	24,489	20,289
Producing property acquisitions	-	7,844
...sposal of property	(6,200)	(600)
Total capital expenditures	18,289	27,533

...nd holdings

...06, Masters' undeveloped land decreased by 18 percent to 82,000 net acres. The decrease is due to a combination of ...ing and undeveloped land converted to developed land as a result of drilling wells. In 2006 Masters acquired 11,683 net ...through crown land sales. The average working interest of the undeveloped lands Masters owned at December 31, 2006 ...12 percent.

The following table sets out our developed and undeveloped land holdings as at December 31, 2006.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
...ta - Northern	58,399	17,256	170,812	63,373	229,211	80,629
...erta - Southern	26,178	17,825	24,546	18,179	50,724	36,004
Total	84,577	35,081	195,358	81,552	279,935	116,633

The following table sets out our developed and undeveloped land holdings as at December 31, 2005.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta - Northern	34,104	9,463	190,411	75,468	224,515	84,931
Alberta - Southern	23,319	15,495	32,367	24,298	55,686	39,793
Total	57,423	24,958	222,778	99,766	280,201	124,724

Finding and development costs

During 2006, our exploration and development program resulted in total proved reserves additions, after prior year revisions, of ...4,000 boe, or 1,318,000 boe on a proved plus probable basis. Masters' total finding and development and net acquisition costs were $19.17 per proved boe and $13.88 per proved plus probable boe. After accounting for the change in future development capital, finding and development and net acquisition costs were $19.27 per proved boe and $14.32 per proved plus probable boe.

The combined 2004 to 2006 capital programs, including the acquisitions of Terraquest and North Peace River Arch, resulted in finding and development and net acquisition costs of $17.47 per proved boe and $13.43 per proved plus probable boe. After accounting for the change to estimated future development capital, finding and development and net acquisition costs were $17.70 per proved boe and $13.71 per proved plus probable boe.

The reserves disclosed for 2006 and 2005 conform with the requirements of National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2006 Finding and development (F&D) and net acquisition (FD&A) costs

	Capital expenditures ($ thousands)	Proved reserves additions (mboe)	Proved costs ($/boe)	Proved plus probable reserves additions (mboe)	Proved plus probable costs ($/boe)
F&D exploration and development programs before revisions	24,489	758	32.31	1,299	18.85
F&D exploration and development program after revisions (a)	24,489	954	25.67	1,318	18.58
Change in proved future development capital (b)	91	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	579	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	24,580	954	25.77	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	25,068	n/a	n/a	1,318	19.02
Net acquisition/(disposition) activity (f)	(6,200)	n/a	n/a	n/a	n/a
Total 2006 FD&A costs before future development costs (a+f)	18,289	954	19.17	1,318	13.88
Total 2006 proved FD&A costs including future development costs (d+f)	18,380	954	19.27	n/a	n/a
Total 2006 proved plus probable FD&A costs including future development costs (e+f)	18,868	n/a	n/a	1,318	14.32

2005 Finding and development (F&D) and net acquisition (FD&A) costs

	Capital expenditures ($ thousands)	Proved reserves additions (mboe)	Proved costs ($/boe)	Proved plus probable reserves additions (mboe)	Proved plus probable costs ($/boe)
F&D exploration and development programs before revisions	20,289	702	28.90	942	21.54
F&D exploration and development program after revisions (a)	20,289	860	23.59	1,110	18.28
Change in proved future development capital (b)	819	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	853	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	21,108	860	24.54	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	21,142	n/a	n/a	1,110	19.05
Net acquisition/(disposition) activity (f)	7,244	424	17.08	633	11.44
Total 2005 FD&A costs before future development costs (a+f)	27,533	1,284	21.44	1,743	15.80
Total 2005 proved FD&A costs including future development costs (d+f)	28,352	1,284	22.08	n/a	n/a
Total 2005 proved plus probable FD&A costs including future development costs (e+f)	28,386	n/a	n/a	1,743	16.29

MANAGEMENT'S DISCUSSION AND ANALYSIS

Combined 2004 to 2006 finding and development (F&D) and net acquisition (FD&A) costs

Masters Energy Inc. commenced operations December 22, 2003 with the acquisition of the Little Bow property in southern Alberta. The combined 2004 to 2006 results are more representative of management's efforts as presented in the table below.

	Capital expenditures ($ thousands)	Proved reserves additions (mboe)	Proved costs ($/boe)	Proved plus probable reserves additions (mboe)	Proved plus probable costs ($/boe)
F&D exploration and development programs before revisions	55,698	1,803	30.89	2,661	20.93
F&D exploration and development program after revisions (a)	55,698	2,386	23.34	3,016	18.47
Change in proved future development capital (b)	1,088	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	1,720	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	56,786	2,386	23.80	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	57,418	n/a	n/a	3,016	19.04
Net acquisition/(disposition) activity (f)	27,638	2,385	11.59	3,190	8.66
Total 2004 to 2006 FD&A costs before future development costs (a+f)	83,336	4,771	17.47	6,206	13.43
Total 2004 to 2006 proved FD&A costs including future development costs (d+f)	84,424	4,771	17.70	n/a	n/a
Total 2004 to 2006 proved plus probable FD&A costs including future development costs (e+f)	85,056	n/a	n/a	6,206	13.71

Reserves replacement

Masters' 2006 capital expenditure program replaced production by a factor of 1.9 times on a proved basis and 2.6 times on a proved plus probable basis.

	2006	2005
Production *(mboe)*	**514**	458
Proved reserves additions after revisions *(mboe)*	**954**	1,169
Proved replacement ratio	**1.86**	2.55
Proved plus probable reserves additions after revisions *(mboe)*	**1,318**	1,610
Proved plus probable replacement ratio	**2.56**	3.52

Recycle ratio

Recycle ratio is a measure for evaluating the effectiveness of a company's re-investment in its exploration and development program. The ratio measures the efficiency of capital investment by comparing the operating netback per boe to that year's finding and development and net acquisition costs per boe.

	2006	2005
Operating netbacks *($/boe)*	**27.77**	30.74
Proved FD&A costs after revisions and including the change in future development cost *($/boe)*	**19.27**	22.08
Proved reinvestment efficiency ratio	**1.4**	1.4
Proved plus probable FD&A costs after revisions and including the change in future development cost *($/boe)*	**14.32**	16.29
Proved plus probable reinvestment efficiency ratio	**1.9**	1.9

Drilling results

During 2006, Masters drilled 31 (2005 - 22) exploration and development wells resulting in nil (2005 - 6) oil wells and 17 (2005 - 10) natural gas wells for an overall success rate of 55 (2005 - 73) percent. Of the total wells drilled, 27 (2005 - 6) were in northern and central Alberta and the remaining four (2005 - 16) were in southern Alberta.

	2006		2005	
wells)	Gross	Net	Gross	Net
Oil	**-**	**-**	6	6.0
Natural gas	**17**	**7.0**	10	7.2
Dry and abandoned	**14**	**7.1**	6	4.4
Total	**31**	**14.1**	22	17.6
Success rate *(%)*	**55**	**50**	73	75

MANAGEMENT'S DISCUSSION AND ANALYSIS



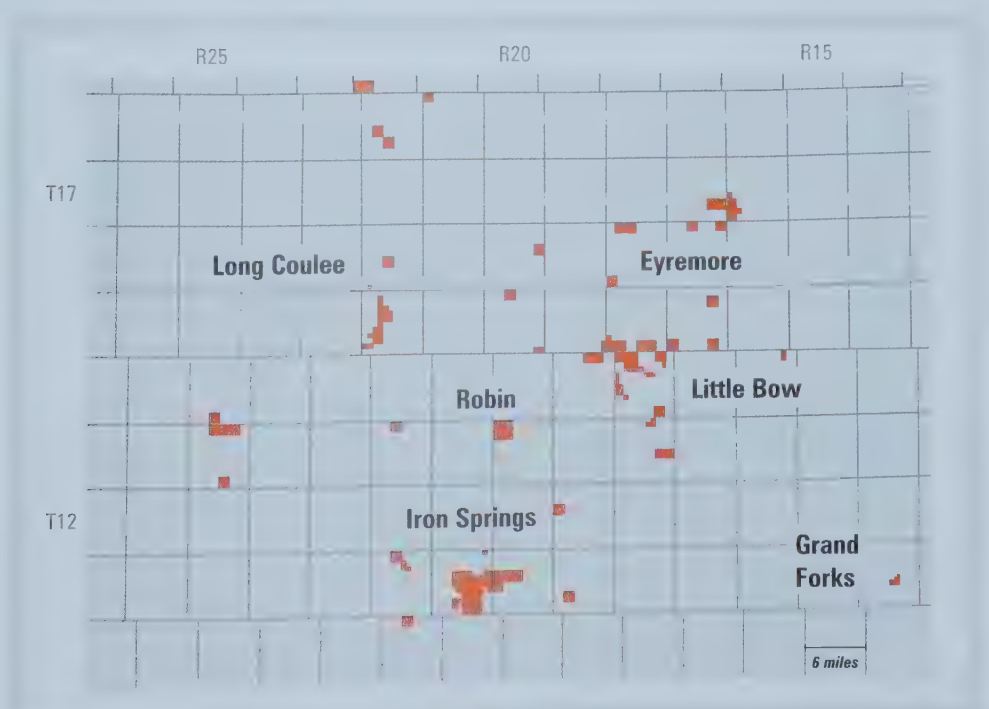
CORE AREA ACTIVITY

In 2007, we will continue to focus on exploiting opportunities within the core producing areas at Little Bow and the North Peace River Arch region as well as concentrating on Masters' large undeveloped land base (approximately 82,000 net acres) in Alberta. We anticipate spending $20 million on exploration and development activities and allocating approximately 40 percent of capital spending to opportunities in the North Peace River Arch area. We also expect to develop numerous new prospects in addition to those currently identified. Capital will be allocated to the exploitation of our core areas and to new exploration prospects outside these areas.

Southern Alberta

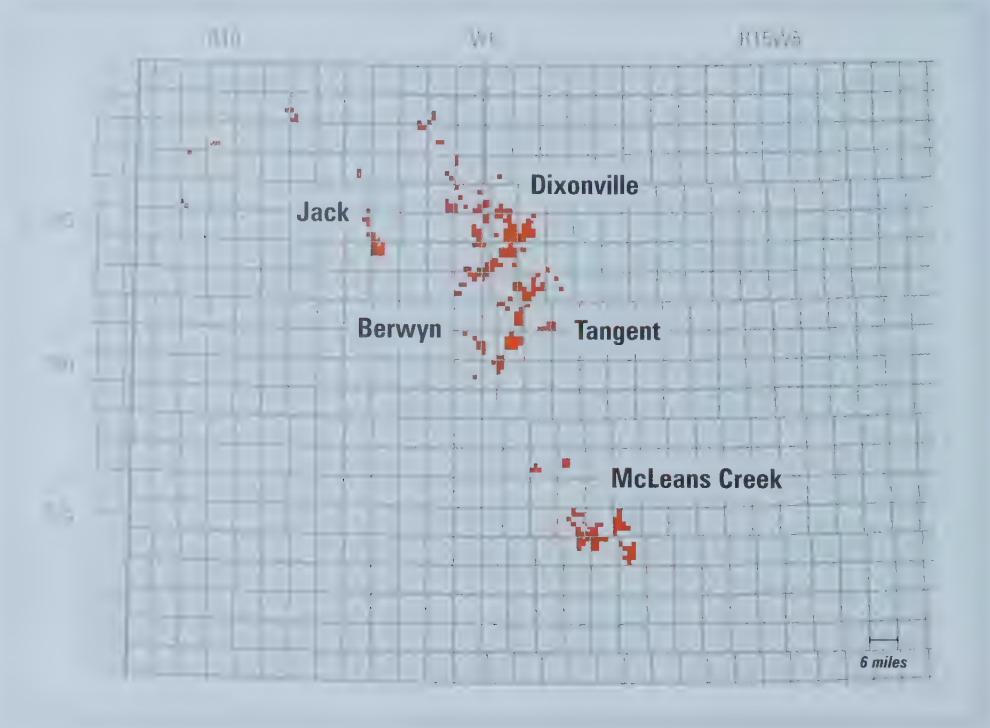
The 2003 acquisition of Little Bow provided Masters with an entry into southern Alberta. At the time of the acquisition, the Little Bow property was producing approximately 450 boe/d. The Terraquest acquisition in February 2004 strategically enhanced Masters' operations in southern Alberta with interests in producing properties at Little Bow, Long Coulee, Grand Forks, Hector and Badger. The Terraquest acquisition also provided 22,000 net acres of undeveloped lands for future drilling.

During 2005, Masters drilled 16 exploration and development wells resulting in six oil wells and six natural gas wells for an overall success rate of 75 percent. At Little Bow, we drilled a total of 10 wells including six infill wells in the main producing pool. We expanded the battery and water handling facility during 2005 and drilled a water injection well into the existing pool. In 2005 and early 2006, Masters completed several 3D seismic surveys on exploratory lands which has resulted in several future drilling locations. We will pursue additional exploration concepts on, or in reasonable proximity to, existing Masters' lands. For 2007, we expect to allocate approximately one half of capital spending to southern Alberta and drill 7-10 medium depth wells. Masters' southern area provided approximately 75 percent of 2006 total production.



Northern and Central Alberta

In 2005, $7.8 million for acquisitions of North Peace River Arch properties created a second core producing area for Masters. These acquisitions provided 160 boe/d of production, 10,600 net undeveloped acres, ownership in several strategic field facilities and a large seismic database associated with the properties. In addition to the initial acquisitions, Masters spent $7.5 million to drill six wells (four were natural gas wells), acquire more than 10,000 net undeveloped acres, expand existing production facilities and complete several large 3D seismic programs. At the end of 2005 and in early 2006, Masters shot approximately 94 square miles of 3D seismic which provided the basis for an active drilling program in 2006. In 2006, Masters drilled 21 wells resulting in 16 natural gas wells, yielding a success rate of 76 percent for the area. Several of the new wells were tied in during the 2006 fourth quarter with the remaining new wells expected to be on-stream in the first quarter of 2007. Generally, the drilling prospects are multi-zone to depths of 1,300 meters, targeting the Montney, Gething, Bluesky, Cadotte, Cadomin, Paddy and Spirit River.



MANAGEMENT'S DISCUSSION AND ANALYSIS

CONTRACTUAL OBLIGATIONS

As part of our land acquisition strategy in our core areas, Masters will commit to industry partners to drill wells, shoot seismic programs or tie-in previously drilled wells to earn interests in undeveloped land. As at the date of this MD&A, Masters has committed to drill two wells. Masters estimates a work commitment amount of approximately $0.6 million. Masters has this commitment scheduled in its 2007 capital expenditures program, currently approved by the Board of Directors at $20.0 million. Masters has contractual obligations on operating leases of field equipment. These operating leases are short term and due within one year, if demanded. The table below shows payments due within the periods indicated.

($ thousands)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Farm-in commitments	620	620	-	-	-
Firm transportation commitments	1,340	334	504	430	72
Operating leases	114	114	-	-	-
Office lease	331	87	244	-	-
Total contractual obligations	2,405	1,155	748	430	72

LIQUIDITY AND CAPITAL RESOURCES

Total capitalization at December 31, 2006 was $78.6 million (2005 - $118.4 million) with the market value of common shares representing 67 percent of total capitalization. Net debt represented 25 percent and asset retirement obligations plus future income taxes accounted for eight percent.

Total market capitalization

($ thousands except as indicated)	2006	%	2005	%
Common shares outstanding *(thousands)*	15,540		14,523	
Closing share price at December 31 *($)*	3.40		6.47	
Total market capitalization	52,836	67	93,966	79
Working capital deficiency, excluding bank debt	2,156		5,013	
Bank debt	17,824		14,093	
Net debt	19,980	25	19,106	16
Asset retirement obligations	3,527	5	3,316	3
Future income taxes	2,283	3	2,005	2
Total capitalization	78,626	100	118,393	100
Net debt to total capitalization	25%		16%	

At December 31, 2006, Masters had borrowed approximately $17.8 (2005 - $14.1) million and had a working capital deficit of $2.2 (2005 - $5.0) million amounting to total net debt of $20.0 (2005 - $19.1) million. Net debt for 2006 represents approximately 1.7 (2005 - 1.6) times funds generated by operating activities of $11.4 (2005 - $12.2) million and approximately 1.0 to 1.1 times budgeted 2007 funds generated by operating activities.

Masters has a bank revolving term facility of $22 million to fund future activities. The facility is a borrowing base facility determined by Masters' latest reserves assessment, results of operations, current and forecasted commodity prices and the prevailing economic market. The facility is reviewed semi-annually in April and October. As at December 31, 2006, Masters had drawn $17.8 million of the revolving term facility.

The capital intensive nature of our activities can create a negative working capital position in quarters with high levels of exploration and development capital spending.

The industry has a pre-arranged monthly settlement day for payment of revenues from all buyers of crude and natural gas. This occurs on the 25th day following the month in which the production is sold. As a result Masters collects sales revenues in an organized manner. Management monitors purchaser credit positions to mitigate any potential credit losses. To the extent Masters has joint interest activities with industry partners we must collect, on a monthly basis, partners' share of capital and operating expenses. These collections are subject to normal industry risk. Masters collects in advance for significant amounts related to partners' share of capital expenditures in accordance with the industry operating procedures. At December 31, 2006, Masters had no material accounts receivable deemed uncollectible.

Accounts payable consists of invoices payable to trade suppliers relating to office and field operating activities and our capital spending program. Masters processes invoices within a normal payment period.

We continually manage Masters' capital spending program by monitoring forecasted production, commodity prices and anticipated cash flow. Should circumstances arise that negatively affect cash flow, Masters is capable of reducing the level of future capital spending.

We will fund our future investing activities, which consist primarily of capital expenditures on oil and natural gas activities, with working capital, funds generated by operations, a limited amount of bank debt and, possibly, from the issuance of new equity.

Debt ratios

(thousands, except as indicated)	2006	2005
Working capital deficiency, excluding bank debt	**2,156**	5,013
Bank debt	**17,824**	14,093
Net debt	**19,980**	19,106
Debt to funds generated by operations ratio		
Funds generated by operations	**11,439**	12,159
Trailing net debt	**19,980**	19,106
Years of funds generated by operations activities to repay trailing net debt		
Current year funds generated by operations	**1.7**	1.6
Estimated forward funds generated by operations	**1.1**	1.2
Asset coverage ratio		
Total assets	**70,275**	60,016
Net debt	**19,980**	19,106
Asset coverage	**3.52**	3.14
Debt/equity ratio		
Net debt	**19,980**	19,106
Shareholders' equity	**39,921**	31,791
Debt/equity	**0.50**	0.60

OUTLOOK

The acquisitions of the North Peace River Arch and Little Bow properties established a strong production base from which Masters can grow. With an experienced technical team, a large undeveloped land base (82,000 net acres) and a number of internally-generated prospects, we can continue to grow. We believe Masters can deliver production averaging 1,800 - 2,000 boe/d in 2007 from internally-generated exploration and development. The Board of Directors has approved a $20 million capital program that will focus on exploiting existing internal opportunities and on continuing to build an inventory of exploration and development opportunities expected to provide growth through 2007 and beyond.

In addition to our ongoing exploration and development program, Masters will seek growth through acquisitions that are strategic and have the potential to add future shareholder value.

2007 Capital budget

Masters' 2006 capital program expanded our core areas in southern and northern Alberta by adding prospective lands and a large seismic data base. Through the efforts of this program we established a large inventory of future drilling opportunities. In 2007 we expect to drill approximately 25 - 30 wells in our current areas of focus.

Masters anticipates 2007 funds generated by operating activities will reach approximately $18-$20 million. This is based on forecasted 2007 average production of 1,800 - 2,000 boe/d, average commodity prices of $72.00 per bbl for Edmonton light quality crude oil (US$61.00 per bbl WTI) and $7.80 per GJ ($8.25 per mcf) for natural gas at AECO, foreign exchange of US$0.85 and costs remaining at historical levels.

We are forecasting our 2007 capital program at $20 million with an approximate allocation of $4 million for land and seismic, $11 million for drilling and completions, and $5 million for equipment and facilities. We forecast net debt of $20.0 million at December 31, 2006 will increase modestly to approximately $20 - $22 million at 2007 year-end.

2007 Sensitivities

Based on the forecast assumption of 1,800 boe/d, Masters provides the following sensitivities to indicate the potential impact on funds generated by operations in the event of changes in commodity prices, the foreign currency exchange rate and average daily production volumes.

($ thousands, except as indicated)	Funds generated by operations	Per share - basic *($)*
Impact on 2007:		
Change in WTI oil price of US$5.00 per bbl	1,480	0.09
Change in natural gas price of Cdn$1.00 per mcf	1,725	0.11
Change in US dollar to Cdn dollar of US$0.01	220	0.01
Change in 100 bbl per day of liquids production	1,150	0.07
Change in 1,000 mcf per day of natural gas production	1,590	0.10

SELECTED QUARTERLY INFORMATION

The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and measurement currency is the Canadian dollar.

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Operations								
Production								
Oil *(bbls/d)*	749	791	781	813	707	688	715	678
NGL *(bbls/d)*	10	10	13	9	10	15	11	6
Natural gas *(mcf/d)*	4,417	2,897	3,543	3,888	3,619	3,872	3,055	2,538
Total *(boe/d)*	1,495	1,284	1,384	1,470	1,320	1,349	1,236	1,107
Pricing								
Oil *($/bbl)*	42.31	58.03	59.65	39.82	42.50	56.92	41.64	38.14
NGL *($/bbl)*	71.65	62.71	61.62	56.87	60.85	59.56	49.56	46.12
Natural gas *($/mcf)*	7.07	5.61	5.91	7.41	11.29	9.09	7.34	6.83
Total *($/boe)*	42.57	48.92	49.34	41.97	54.18	55.84	42.71	39.28
Financial								
($ thousands, except as indicated)								
Total revenue	5,960	5,971	6,545	5,788	6,908	7,175	4,836	4,010
Funds generated by operations	2,200	3,144	3,553	2,542	2,915	4,476	2,699	2,069
Net earnings	26	815	800	217	630	1,781	643	557
Per share - basic *($)*	0.00	0.05	0.05	0.02	0.04	0.12	0.04	0.04
Per share - diluted *($)*	0.00	0.05	0.05	0.01	0.04	0.12	0.04	0.04
Capital spending								
Exploration and development	6,022	5,625	4,487	8,355	11,570	2,805	2,806	3,108
Acquisitions/ (dispositions)	-	(6,200)	-	-	31	(339)	7,552	-
Total assets	70,275	65,176	66,533	64,228	60,016	51,142	48,130	38,830
Working capital (deficiency)	(2,156)	(1,904)	(1,496)	(7,477)	(5,013)	1,381	323	(5,155)
Long-term debt	17,824	14,467	18,584	17,442	14,093	11,911	13,137	-
Shareholders' equity	39,921	39,861	38,940	32,064	31,791	31,033	28,884	28,184
Common shares								
Weighted average common shares outstanding *(thousands)*								
Basic	15,559	15,570	15,356	14,523	14,491	14,462	14,364	14,364
Diluted	15,974	16,093	16,052	15,433	15,482	15,146	14,931	14,801
Trading activity								
Volume *(thousands)*								
Total	865	773	804	1,757	2,351	2,467	3,096	4,149
Daily	14	12	13	27	38	39	48	67
Price *($ per share)*								
High	4.08	4.28	5.39	6.75	6.95	4.70	3.80	4.20
Low	3.00	3.25	3.56	4.25	4.60	3.62	3.05	2.31
Closing	3.40	3.35	3.80	4.89	6.47	4.55	3.64	3.40

MANAGEMENT'S DISCUSSION AND ANALYSIS

Factors that caused variations over the quarters

Masters completed four significant acquisitions since its initial financing in the fourth quarter of 2003 which have impacted production growth.

- The acquisition of the Little Bow property in southern Alberta on December 22, 2003 added approximately 450 boe per day consisting of approximately 90 percent crude oil production. Proved plus probable reserves acquired were approximately 1.4 million boe with an estimated reserves life index of 8.6 years.

- The acquisition of Terraquest Energy Corporation on February 26, 2004 added production of approximately 400 boe per day consisting of approximately 60 percent natural gas. Proved plus probable reserves acquired were approximately 1.1 million boe with an estimated reserves life index of 7.9 years based on production at the time of acquisition.

- The two acquisitions of producing properties in the North Peace River Arch area of northwest Alberta on June 3, 2005 and September 12, 2005 added approximately 160 boe per day consisting primarily of natural gas production. Proved plus probable reserves acquired were approximately 0.5 million boe with an estimated reserves life index of 7.0 years.

Production growth, other than the acquisitions, is a result of Masters' exploration and development activities. Timing of production is subject to timing of drilling and facility construction.

Growth in revenue and funds generated by operations is the combination of increased production and strong commodity prices. Generally, commodity prices were consistently strong throughout 2004 and 2005. Oil prices for medium grade quality crude experienced a large drop in the latter portion of the 2004 fourth quarter due to wider than historical quality differentials. This impacted the prices Masters received since that time as a majority of our crude production is medium quality.

Depletion, depreciation, accretion and future income taxes influence net earnings. Masters estimates reserves internally every quarter based on acquisition and drilling activities. Independent qualified reserves evaluators determine annual reserves, the results of which can affect fourth quarter reserves additions. Enacted changes to federal and provincial income tax rates for the oil and gas industry impact future income taxes.

The development of future drilling prospects and seasonal field conditions influence capital spending. Funds generated by operations, bank debt and the issuance of common shares primarily funded capital spending.

FOURTH QUARTER ANALYSIS

	Q4 2006	Q3 2006	Q4 2005	% Change Q4 2006 vs Q3 2006	% Change Q4 2006 vs Q4 2005
Operations results					
Production					
Crude oil *(bbls/d)*	**749**	**791**	707	(5)	6
NGL *(bbls/d)*	**10**	**10**	10	-	-
Natural gas *(mcf/d)*	**4,417**	**2,897**	3,619	53	22
Total *(boe/d)*	**1,495**	**1,284**	1,320	16	13
Crude oil *($/bbl)*	**42.31**	**58.03**	42.50	(27)	-
NGL *($/bbl)*	**71.65**	**62.71**	60.85	14	18
Natural gas *($/mcf)*	**7.07**	**5.61**	11.29	26	(37)
Selected financial results					
(thousands, except as indicated)					
Total revenue	**5,960**	**5,971**	6,908	-	(14)
Royalties	**(1,147)**	**(733)**	(1,815)	56	(37)
Operating expense	**(1,842)**	**(1,463)**	(1,471)	26	25
General and administrative	**(549)**	**(253)**	(398)	117	38
Funds generated by operations	**2,200**	**3,144**	2,915	(30)	(25)
Depletion, depreciation and accretion	**2,503**	**2,033**	2,184	23	15
Net earnings	**26**	**815**	630	(97)	(96)
Per share -basic *($)*	**0.00**	**0.05**	0.04		
Per share - diluted *($)*	**0.00**	**0.05**	0.04		
Capital spending					
Exploration and development	**6,022**	**5,625**	11,570	7	(48)
Acquisitions/(dispositions)	**-**	**(6,200)**	31	-	-
Total capital spending	**6,022**	**(575)**	11,604	1,047	(48)
Working capital deficiency	**2,156**	**1,904**	5,013	13	(57)
Long-term debt	**17,824**	**14,467**	14,093	23	26
Shareholders' equity	**39,921**	**39,861**	31,791	-	26
Weighted average common shares outstanding *(thousands)*					
Basic	**15,559**	**15,570**	14,491		
Diluted	**15,974**	**16,093**	15,482		

MANAGEMENT'S DISCUSSION AND ANALYSIS

PRODUCTION

Production for the fourth quarter 2006 increased 16 percent to 1,495 boe/d compared to the 2006 third quarter at 1,284 boe/d and increased 13 percent compared to the 2005 fourth quarter. The production increase in the 2006 fourth quarter occurred when we brought 10 wells on-stream. During the month of December 2006 production averaged 1,600 boe/d. Production increases since the 2005 fourth quarter are due to placing successful wells on-stream.

REVENUES

Revenues for the 2006 fourth quarter remained unchanged at $6.0 million compared to the 2006 third quarter and decreased 14 percent from the 2005 fourth quarter. In the quarter ended December 31, 2006, Edmonton Par postings were lower for crude oil compared to the third quarter. Natural gas spot prices increased in the fourth quarter 2006 compared to the third quarter 2006, but were down 37 percent compared with the 2005 fourth quarter.

ROYALTIES

Royalties for the 2006 fourth quarter increased 56 percent to $1.1 million compared to $0.7 million in the 2006 third quarter and decreased 37 percent from the 2005 fourth quarter. The majority of royalty expense incurred during the quarters was payable to the crown. Royalties for the three month period ended December 31, 2006 decreased from the same period in 2005 as a result of lower natural gas revenues. We anticipate the future average royalty rate relative to oil and natural gas revenues will be consistent with historical royalty rates.

OPERATING EXPENSES

Operating expenses for the 2006 fourth quarter increased 27 percent to $1.8 million from $1.5 million in the 2006 third quarter. Several one-time charges increased the operating costs in the quarter. An unusually large ($190,000) third party processing charge adjustment and abnormally high electrical power rates (approximately $150,000 higher than normal) pushed operating expenses higher than anticipated in the 2006 fourth quarter. For the three months ended December 31, 2006 operating expenses increased 25 percent from the same period in 2005 as result of the previously noted exceptions and higher production. Masters forecasts operating costs will average approximately $9.50 per boe during 2007.

GENERAL AND ADMINISTRATIVE

The 2006 fourth quarter general and administrative expense increased 117 percent to $0.5 million from the 2006 third quarter and 38 percent from the 2005 fourth quarter. General and administrative expenses averaged $3.99 per boe for the 2006 fourth quarter compared to $2.14 per boe in the 2006 third quarter and $3.28 per boe in the 2005 fourth quarter. The 2006 fourth quarter general and administrative expenses include provisions for the annual audit and reserves reports ($150,000). Masters forecasts 2007 general and administrative expenses, including a non-cash provision for future stock-based compensation of approximately $1.0 million, at approximately $2.80 per boe.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion expense for the 2006 fourth quarter was $2.5 million compared to $2.0 million for the 2006 third quarter and $2.2 million for the 2005 fourth quarter. Depletion, depreciation and accretion provision for the 2006 fourth quarter was $18.19 per boe compared to $17.20 per boe in the 2006 third quarter and $17.98 per boe for the 2005 fourth quarter. The depletion rate per boe for the 2006 fourth quarter reflected the disproportionate amount of 2006 equipment and facility installation activities that occurred during the fourth quarter.

INCOME TAXES

The future income tax recovery provision for the 2006 fourth quarter was $0.1 million compared to $0.4 million expense for the 2006 third quarter and $0.3 million expense for the 2005 fourth quarter. The increase for the fourth quarter 2006 recovery of taxes is due to a loss before taxes recovered.

NET EARNINGS

Net earnings for the 2006 fourth quarter were $nil compared to $0.8 million for the 2006 third quarter and $0.6 million during the 2005 fourth quarter. The decrease in net earnings recorded in the 2006 fourth quarter compared to 2006 third quarter is mainly due to higher royalty and operating expenses. For the three months ended December 31, 2006, the decrease in net earnings compared to the 2005 fourth quarter is due to higher depletion, depreciation and accretion expense.

CAPITAL EXPENDITURES

During the 2006 fourth quarter, Masters spent $6.0 million on exploration and development capital including $0.2 million in land, $0.6 million in seismic, $2.6 million in drilling and completions and $2.8 million in facilities. During the quarter ended December 31, 2006, five wells were drilled resulting in four natural gas wells, acquired 640 net acres of undeveloped land; and installed natural gas facilities to bring on-stream 10 natural gas wells.

Capital spending during the 2006 fourth quarter was $6.0 million compared to $5.6 million in the 2006 third quarter and to $11.6 million in the 2005 fourth quarter.

CRITICAL ACCOUNTING ESTIMATES

i. Depletion and depreciation expense of petroleum and natural gas properties

Masters follows the full cost method of accounting by initially capitalizing all costs related to exploration for, and the development of, petroleum and natural gas reserves. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and lease and well equipment. Costs capitalized are depleted and depreciated using the unit-of-production method based upon gross proved petroleum and natural gas reserves as determined by independent qualified reserves evaluators. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content, where one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The depletion and depreciation base excludes the cost of significant unproved properties until it is determined whether proved reserves are attributable to the properties, or impairment has occurred.

Masters performs a ceiling test, whereby, if the carrying value of the oil and natural gas properties less accumulated depletion and depreciation, related asset retirement obligations and the lesser of cost and fair value of unproven properties exceeds the estimated future cash flows from the proved and probable oil and natural gas reserves, discounted at the company's credit-adjusted risk-free rate of interest, using forecast prices and costs. Any impairment recognized is recorded as additional depletion and depreciation expense.

Estimates are the basis for amounts recorded for depletion and depreciation of oil and natural gas properties, and the ceiling test. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

2. Asset retirement obligations

Masters recognizes the liability for asset retirement obligations associated with the abandonment of oil and natural gas wells, related facilities, compressors and plants, removal of equipment from leased acreage and returning such land to its original condition. The fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the company's credit-adjusted risk-free interest rate. Future costs are estimates that are subject to measurement uncertainty and any change would impact the liability.

3. Stock-based compensation

The amounts disclosed relating to the fair value of stock options and performance warrants issued and the resulting income effect are based on estimates of the future volatility of Masters' share price, expected lives of the options, expected dividends and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

4. Income taxes

The determination of the company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability and expense may differ from that estimated and recorded.

CHANGES IN ACCOUNTING PRINCIPLES

Masters did not adopt any changes in accounting principles in 2006.

RECENT ACCOUNTING PRONOUNCEMENTS

Management is assessing the following new and revised accounting pronouncements that have been issued and are not yet effective:

1. Financial instruments

Commencing January 1, 2007, the following CICA standards regarding financial instruments are in effect;

a. CICA handbook section 3855 "Financial Instruments - Recognition and Measurement",
b. CICA handbook section 3861 "Financial Instruments - Disclosure and Presentation",
c. CICA handbook section 1530 "Comprehensive Income", and
d. CICA handbook section 3865 "Hedges".

The standards require inclusion of all financial instruments other than held-to-maturity investments, loans and receivables, on a company's balance sheet at their fair value. Held-to-maturity investments, loans and receivables would be measured at their amortized cost. The standards create a new statement of comprehensive income that will include changes in fair value of certain derivative financial instruments. The Company elects to mark-to-market its derivative contracts under its risk management program. The accounting for hedging relationships for prior fiscal years is not retroactively changed. Therefore, management expects no restatement of prior periods as a result of these new standards.

2. International financial reporting standards ("IFRS")

Over the next five years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada ratified in 2006. As part of that plan, accounting standards in Canada for public companies will converge with IFRS over the next five years. Masters will continue to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to ensure that information Masters is required to disclose is accumulated and communicated to management, as appropriate, to allow timely disclosure. The Chief Executive Officer and Chief Financial Officer evaluated Masters' disclosure controls and procedures as of December 31, 2006 and concluded that Masters' design of the disclosure controls and procedures were appropriate to ensure that information the Company is required to disclose in its annual and interim filings or other reports (as defined in National Instrument 52-109 of the Canadian Securities Administrators) filed or submitted under provincial legislation is recorded, processed, summarized and reported within the time periods specified in the provincial securities legislation and to ensure that information required to be disclosed by Masters is accumulated and communicated to company management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The evaluation took into consideration Masters' Disclosure Policy and the functioning of its executive officers, board of directors and board committees. In addition, the evaluation covered the company's processes, systems and capabilities relating to regulatory filings, public disclosures and the identification and communication of material information. All controls and procedures, no matter how well designed, have inherent limitations. These disclosure controls and procedures provide reasonable, but not absolute, assurance that financial information is accurate and complete.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Through the design of controls certain weaknesses have been identified. The inherit weaknesses are the result of the Company size and the limited number staff and include:

i. the inability to achieve complete segregation of duties; and
ii. having sufficient financial staff with the required technical knowledge to deal with complex and non-routine accounting matters.

The Company believes these weaknesses are mitigated by:

i. the Chief Executive Officer and Chief Financial Officer overseeing all material transactions;
ii. the audit committee, comprised of independent members of the Board of Directors, reviewing the quarterly interims and annual audited financial statements with management;
iii. the Board of Directors approval of the financial statements based on the audit committee's recommendation after its review; and
iv. the Company consulting with its third party expert advisors as needed in connection with the recording and reporting of complex and non-routine transactions.

These mitigating factors will not necessarily prevent the likelihood that a material misstatement will not occur as a result of the aforesaid weaknesses in the Company's internal controls over financial reporting. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met. The officers' Certification of Annual Filings is filed and available on SEDAR at www.sedar.com.

BUSINESS RISKS AND UNCERTAINTIES

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector.

Masters is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Masters' business has inherent risk and there is no assurance that Masters will discover or economically produce hydrocarbon reserves. Financial risks associated with the petroleum industry include market fluctuations in commodity prices, interest rates and currency exchange rates. Operational risks include industry competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The exploration for and production of crude oil and natural gas requires manpower and capital. Masters employs highly qualified experienced staff who have demonstrated the ability to generate quality drilling prospects utilizing the latest technological tools to increase the probability of success. The probability of drilling a successful well is enhanced when the company explores in core areas that have multi-zone potential, focusing on low-to-moderate risk prospects with a limited exposure to high-risk, high-reward opportunities. Masters maintains operational control in a majority of its prospects, which enables management to control the timing, assignment of resources and capital invested in exploration and development opportunities.

A wide number of factors beyond Masters' control influence commodity prices. To manage this risk, we concentrate in regions which permit multiple delivery points to markets and enter into fixed price commodity contracts, on a limited portion of production, within the Company's self imposed hedging guideline.

The acquisition of undeveloped mineral leases, supply of services and production equipment at competitive prices is essential to the ability to add reserves at a competitive cost and to produce these reserves in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult and expensive to obtain. Increased prices for supplies and services can inflate costs of operations and potentially erode product netbacks. Masters attempts to mitigate this risk by developing strong long-term relationships with industry participants, suppliers and contractors.

There are potential risks to the environment inherent to Masters' business activities. To mitigate these risks, Masters conducts high standards of operations and follows safety procedures designed to protect and maintain the environment and public and employee safety, with respect to all corporate operations on behalf of shareholders, staff and stakeholders at large. Masters minimizes environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and carrying adequate insurance coverage.



ADDITIONAL INFORMATION

Additional information about Masters, including our Annual Information Form (AIF), is filed and viewable on SEDAR at www.sedar.com. To request a copy of the AIF, contact Masters Energy Inc. 1150, 736 - 6th Avenue SW, Calgary, Alberta, Canada T2P 3T7 or e-mail boyd@mastersenergy.com. This information is also accessible on Masters' web site www.mastersenergy.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Masters is responsible for the preparation and disclosure of information with respect to the Corporation's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs;
(ii) the related estimated future net revenue;
(b) (i) proved oil and natural gas reserves estimated as at December 31, 2006 using constant prices and costs; and
(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of the Corporation has:

(c) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
(d) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(e) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(f) the content and filing with securities regulatory authorities of the reserves data and other oil and natural gas information;
(g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
(h) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Geoffrey C. Merritt
President and Chief Executive Officer

Randall P. Boyd
Chief Financial Officer

Fred Coles
Director and Chair of the Reserves Committee

Kerry D. Lyons
Director and Member of the Reserves Committee

March 9, 2007

REPORT OF INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of Directors of Masters Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2006. The reserves data consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and
(ii) the related estimated future net revenue; and
(b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
(ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2006, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management:

Independent qualified reserves evaluator or auditor	Preparation date of evaluation report	Location of reserves (country or foreign geographic area)	Net present value of future net revenue (before income taxes, 10% discount rate) ($ thousands)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	February 21, 2007	Canada	$nil	$76,736	$nil	$76,736

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

7. We have no responsibility to update our report for events and circumstances occurring after the preparation date.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

P.A. Welch
McDaniel & Associates Consultants Ltd.
Calgary, Alberta
February 21, 2007

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated February 21, 2007. The effective date of the Statement is December 31, 2006 and the preparation date of the Statement is February 21, 2007.

Disclosure of reserves data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by McDaniel with an effective date of December 31, 2006 contained in the McDaniel Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51 101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. All of the Corporation's reserves are in Canada and, specifically, in the province of Alberta.

Disclosure provided herein in respect of boe units may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf equals 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

RESERVES DATA - CONSTANT PRICES AND COSTS

Summary of oil and gas reserves and net present values of future net revenue
As of December 31, 2006
Constant prices and costs

	Reserves							
Reserves	Light and medium oil		Natural gas liquids		Natural gas		Total	
category	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mmcf)	(mmcf)	(mboe)	(mboe)
Proved								
Developed producing	1,779	1,576	9	6	4,490	3,450	2,537	2,157
Developed non-producing	289	253	12	8	3,209	2,282	835	641
Undeveloped	-	-	-	-	-	-	-	-
Total proved	2,068	1,829	20	14	7,699	5,732	3,371	2,798
Probable	711	618	9	6	4,258	3,218	1,430	1,160
Total proved plus probable	2,779	2,447	29	19	11,956	8,950	4,801	3,958

Reserves category	Net present values of future net revenue: Before income taxes discounted at (percent per year) 0	5	10	15	20	After income taxes discounted at (percent per year) 0	5	10	15	20
Proved										
Developed producing	59.3	48.1	40.8	35.7	31.9	55.5	45.6	39.0	34.3	30.8
Developed non-producing	15.5	12.9	11.1	9.8	8.7	10.8	9.0	7.7	6.7	6.0
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total proved	74.8	61.1	51.9	45.5	40.6	66.3	54.5	46.6	41.0	36.8
Probable	33.5	22.8	17.0	13.4	11.0	23.8	16.1	11.9	9.3	7.6
Total proved plus probable	108.3	83.9	68.9	58.8	51.6	90.1	70.6	58.5	50.4	44.5

Total future net revenue (undiscounted)
As of December 31, 2006
Constant prices and costs

Reserves category	Revenue	Royalties	Operating costs	Development costs	Well abandonment costs	Future net revenue before income taxes	Income taxes	Future net revenue after income taxes
Proved reserves	148,437	23,003	44,983	2,375	3,295	74,782	8,502	66,279
Proved plus probable reserves	209,305	33,479	61,021	3,187	3,290	108,328	18,239	90,088

Future net revenue by production group
As of December 31, 2006
Constant prices and costs

Reserves category	Production group	Future net revenue before income taxes (discounted at 10 percent per year)
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	36,218
	Natural gas (including by-products but excluding solution gas from oil wells)	15,717
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	45,209
	Natural gas (including by-products but excluding solution gas from oil wells)	23,709

RESERVES DATA - FORECAST PRICES AND COSTS

Summary of oil and gas reserves and net present values of future net revenue
As of December 31, 2006
Forecast prices and costs

	Reserves							
Reserves category	Light and medium oil		Natural gas liquids		Natural gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mmcf)	(mmcf)	(mboe)	(mboe)
Proved								
Developed producing	1,779	1,575	9	6	4,501	3,455	2,538	2,157
Developed non-producing	288	253	11	8	3,210	2,289	835	642
Undeveloped	-	-	-	-	-	-	-	-
Total proved	2,067	1,828	20	14	7,711	5,744	3,373	2,799
Probable	710	617	9	6	4,187	3,176	1,417	1,152
Total proved plus probable	2,778	2,445	29	19	11,898	8,920	4,790	3,951

	Net present values of future net revenue									
	Before income taxes discounted at					After income taxes discounted at				
Reserves category	(percent per year)					(percent per year)				
	0	5	10	15	20	0	5	10	15	20
($ millions)										
Proved										
Developed producing	61.2	50.3	43.0	37.9	34.0	56.7	47.1	40.5	35.9	32.4
Developed non-producing	18.6	15.5	13.3	11.7	10.4	13.0	10.7	9.2	8.0	7.1
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total proved	79.8	65.9	56.4	49.5	44.4	69.6	57.8	49.7	43.9	39.5
Probable	40.1	27.4	20.4	16.0	13.1	28.4	19.3	14.3	11.2	9.1
Total proved plus probable	120.0	93.3	76.7	65.6	57.5	98.1	77.1	64.0	55.0	48.6

Total future net revenue (undiscounted)
As of December 31, 2006
Forecast prices and costs

Reserves category	Revenue	Royalties	Operating costs	Development costs	Well abandonment costs	Future net revenue before income taxes	Income taxes	Future net revenue after income taxes
($ thousands)								
Proved reserves	165,279	26,387	52,317	2,447	4,278	79,849	10,211	69,638
Proved plus probable reserves	240,626	39,237	73,558	3,322	4,533	119,976	21,925	98,050

Future net revenue by production group
As of December 31, 2006
Forecast prices and costs

Reserves category	Production group	Future net revenue before income taxes (discounted at 10 percent per year)
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	34,994
	Natural gas (including by-products but excluding solution gas from oil wells)	21,358
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	44,130
	Natural gas (including by-products but excluding solution gas from oil wells)	32,607

Notes to reserves data tables:

(1) Columns may not add due to rounding.

(2) The crude oil, natural gas liquids and natural gas reserves estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is provided below.

Reserves categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

(c) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of certainty for reported reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast prices and costs

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at January 1, 2007, inflation and exchange rates utilized by McDaniel in the McDaniel Report (which were McDaniel's then current forecast at the date of the McDaniel Report) were as follows.

Summary of pricing and inflation rate assumptions
As of December 31, 2006
Forecast prices and costs

	Oil			Natural gas	Natural gas liquids		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton par price 40° API ($Cdn/bbl)	Bow River medium 25° API ($Cdn/bbl)	AECO gas price ($Cdn/GJ)	Edmonton mix ($Cdn/bbl)	Inflation rates[1] (%/year)	Exchange rate[2] ($US/$Cdn)
Forecast							
2007	62.50	70.80	49.30	6.85	50.80	2.0	0.87
2008	61.20	69.30	49.60	7.05	50.10	2.0	0.87
2009	59.80	67.70	49.80	7.40	49.50	2.0	0.87
2010	58.40	66.10	49.30	7.50	48.60	2.0	0.87
2011	56.80	64.20	47.90	7.70	47.60	2.0	0.87
Thereafter	+ 2.0%/yr	+ 2.0%/yr	+ 2.0%/yr	+ 2.0%/yr	+ 2.0%/yr	+ 2.0%/yr	0.87

Notes:
(1) *Inflation rates for forecasting prices and costs.*
(2) *Exchange rates used to generate the benchmark reference prices in this table.*

Weighted average historical prices realized by the Corporation for the year ended December 31, 2006, were $6.59 per mcf for natural gas, $49.99 per bbl for crude oil and $63.33 per bbl for natural gas liquids.

Constant prices and costs

Constant prices and costs are:

(a) the Corporation's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) except, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Corporation's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the McDaniel Report were as follows.

Summary of pricing assumptions
As of December 31, 2006
Constant prices and costs

	Oil			Natural gas	Natural gas liquids	
Year	WTI NYMEX	Edmonton par price 40° API	Bow River medium 25° API	Alberta average gas price	Edmonton mix	Exchange rate[1]
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/bbl)*	*($Cdn/GJ)*	*($Cdn/bbl)*	*($US/$Cdn)*
2007+	61.05	67.06	49.66	5.93	48.10	0.8581

Notes:
(1) The exchange rate as at December 29, 2006.

5. Future development costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below.

	Forecast prices and costs				Constant prices and costs	
	Proved reserves		Proved plus probable reserves		Proved reserves	
	Drilling & comp	Equip & facilities	Drilling & comp	Equip & facilities	Drilling & comp	Equip & facilities
($ thousands)						
2007	383	1,826	522	2,070	375	1,790
2008	-	-	13	-	-	-
2009	-	93	-	93	-	88
2010	-	-	-	-	-	-
2011	-	-	137	-	-	-
Thereafter	86	60	428	60	73	50
Total undiscounted	469	1,978	1,100	2,223	448	1,928
Total discounted at 10%	431	1,816	962	1,943	413	1,779

In all the years of the economic forecasts, the net revenues from the reserves are well in excess of the estimated future development costs. Therefore, the Corporation can meet funding requirements for future development entirely out of its cash flow and no other source of funding is required to develop the proved or the proved plus probable reserves.

6. The Alberta Royalty Tax Credit is not included in the cumulative cash flow amounts. The Alberta government announced in 2006 the ARTC program was terminated effective January 1, 2007.

7. Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.

8. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

9. The extent and character of all factual data supplied to McDaniel, were accepted by McDaniel, as represented. No field inspection was conducted.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reconciliation of company gross reserves by principal product type
Forecast prices and costs

	Light and medium oil			Natural gas liquids			Associated and non-associated gas		
	Proved	Probable	Proved plus probable	Proved	Probable	Proved plus probable	Proved	Probable	Proved plus probable
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mmcf)
December 31, 2005	1,837	526	2,362	22	9	31	6,446	3,109	9,556
Discoveries/ extensions	237	178	415	-	-	-	3,126	2,180	5,306
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	279	7	287	2	-	2	(516)	(1,102)	(1,619)
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	(286)	-	(286)	(4)	-	(4)	(1,345)	-	(1,345)
December 31, 2006	2,067	710	2,778	20	9	29	7,711	4,187	11,898

Reconciliation of changes in net present values of future net revenue after tax
Discounted at 10 percent per year
Proved reserves
Constant prices and costs

Period and factor	2006
Estimated future net revenue at beginning of year	50.3
Sales and transfers of oil and gas produced, net of production costs and royalties	(19.5)
Net change in prices, production costs and royalties related to future production	(5.8)
Changes in previously estimated development costs incurred during the period	-
Changes in estimated future development costs	(0.1)
Extensions and improved recovery	3.0
Discoveries	11.6
Acquisitions of reserves	-
Dispositions of reserves	-
Accretion of discount	1.9
Net change in income taxes	5.2
Estimated future net revenue at end of year	46.6

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped reserves

Proved undeveloped reserves

Proved undeveloped reserves are within the following categories:

- Wells budgeted and scheduled to be drilled in 2007.
- Gas caps that will be blown down once the oil has been depleted.
- Secondary zones that will be brought on production once the primary zone has been depleted.

The Corporation does not carry proved undeveloped reserves for long periods of times.

Probable undeveloped reserves

The Corporation's probable reserves are attributed to more optimistic recoveries from producing wells. The remaining probable reserves for the most part are attributed to step-out drilling locations, recompletions, and tie-ins that are anticipated to proceed in the near term but do not meet the required confidence factor to be booked as proved. The comments regarding the Corporation's efforts to put proved undeveloped reserves on-stream also apply to probable reserves.

Significant factors or uncertainties

Estimates of economically recoverable oil and natural gas reserves (including NGL) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from the actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

OTHER OIL AND GAS INFORMATION

Principal properties

Following is a description of Masters oil and natural gas properties as at December 31, 2006. Production stated is net to Masters. Reserves amounts are stated, before deduction of royalties, at December 31, 2006 based on forecast costs and prices as evaluated in the McDaniel Report (see "Reserves Data"). The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2006.

Little Bow, Alberta

Masters purchased the Little Bow property on December 22, 2003. Little Bow is located approximately 50 miles north of Lethbridge, Alberta. Masters has an average working interest of 49 percent in 6,120 (3,003 net) acres of developed land and an average 66 percent working interest in 4,000 (2,628 net) acres of undeveloped lands. As at December 31, 2006, Masters operated the majority of this area's 27 producing wells.

During 2004, Masters conducted an independent reservoir simulation study on the Glauconite oil pool and concluded that further infill drilling and waterflood optimization would enhance the recovery of hydrocarbons. Masters successfully drilled six (6.0 net) infill wells in 2005 and enhanced the waterflood effectiveness by expanding the water handling facility and drilling a water injection well. Masters also completed a 3D seismic program on some of the exploration lands held in this area. The area offers multi-zone oil and natural gas potential at depths to approximately 1,400 meters.

In addition to the wells drilled in the Glauconite oil pool, four (2.6 net) exploration wells were drilled in 2005 resulting in two (1.5 net) natural gas wells. As at December 31, 2006, McDaniel estimated total proved and probable reserves to be 2,460 mbbls of crude oil and NGL and 1,389 mmcf of natural gas. Production averaged 697 bbls/d (2005 - 594 bbls/d) of crude oil and NGL and 219 mcf/d (2005 - 208 mcf/d) of natural gas for the year ended December 31, 2006.

Badger, Alberta

The Badger area is located approximately 60 miles north of Lethbridge, Alberta. Masters has an average working interest of 43 percent in 3,040 (1,321 net) acres of developed land and an average 14 percent working interest in 1,760 (240 net) acres of undeveloped land. As at December 31, 2006, three (0.6 net) producing wells were in the area.

A Glauconite natural gas well (0.3 net) drilled in 2003 commenced production in April 2004.

As at December 31, 2006, McDaniel estimated total proved and probable reserves to be 5.5 mbbls of NGL and 800 mmcf of natural gas. Production averaged 3 bbls/d (2005 - 3 bbls/d) of NGL and 394 mcf/d (2005 - 412 mcf/d) of natural gas for the year ended December 31, 2006.

Eyremore, Alberta

The Eyremore area is located approximately 30 miles east of the town of Vulcan. Masters has a 100 percent working interest in 1,000 acres of land in this area.

The primary exploration target in this area is the Ostracod zone, at depths of 1,200 metres, with secondary targets in the Upper and Lower Mannville zones. During 2004, Masters drilled one natural gas well which was brought on-stream in November 2004 at 1.2 mmcf/d. In 2005 three natural gas wells were drilled and brought onstream in November 2005.

During 2006, Masters recompleted one well as a natural gas well and brought it on-stream.

As at December 31, 2006, McDaniel estimated total proved and probable reserves in this area to be 690 mmcf of natural gas and 2.6 mbbls of NGL.

Production from the Eyremore area averaged 553 mcf/d (2005 - 958 mcf/d) of natural gas and 2 bbls/d (2005 - 4 bbls/d) of crude oil and NGL for the year ended December 31, 2006.

Iron Springs, Alberta

The Iron Springs area is located approximately 10 miles north of the city of Lethbridge. Masters has an average working interest of 96 percent in 9,578 (9,194 net) acres of land and six (6.0 net) producing natural gas wells and one (1.0 net) cased natural gas well in this area.

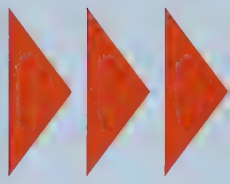
As at December 31, 2006, McDaniel estimated total proved and probable natural gas reserves in this area to be 360 mmcf. Production from the Iron Springs area averaged 175 mcf/d (2005 - 346 mcf/d) of natural gas for the year ended December 31, 2006.

Long Coulee, Alberta

The Long Coulee area is located approximately 30 miles north of the city of Lethbridge. Masters has an average 32 percent working interest in 3,992 (1,275 net) acres of land and nine (4.1 net) producing oil wells in this area.

McDaniel estimated total proved and probable reserves in this area to be 147 mbbls of crude oil and 50 mmcf of natural gas at December 31, 2006.

Production from the Long Coulee area averaged 39 bbls/d (2005 - 39 bbls/d) of crude oil and 13 mcf/d (2005 - 14 mcf/d) of natural gas for the year ended December 31, 2006.



MANAGEMENT'S DISCUSSION AND ANALYSIS

McLeans Creek, Alberta

The McLeans Creek area is located approximately 35 miles west of the town of High Prairie. Masters has an average working interest of 47 percent in 36,800 (17,140 net) acres of undeveloped land and two (0.8 net) producing oil wells in this area. The primary crude oil exploration target is the Granite Wash zone, with secondary natural gas targets in the Bluesky and Paddy zones. In 2007 Masters plans to re-enter one well.

As at December 31, 2006, McDaniel estimated total proved and probable crude oil reserves in this area to be 28.4 mbbls.

Production from the McLeans Creek area averaged 10 bbls/d (2005 - 30 bbls/d) of crude oil for the year ended December 31, 2006.

Robin, Alberta

The Robin area is located approximately 20 miles northeast of the city of Lethbridge. Masters has an average working interest of 70 percent in 2,849 (1,963 net) acres of land and five (3.4 net) producing natural gas wells.

During 2004, Masters drilled two (1.4 net) wells resulting in one (0.6 net) natural gas well and one (0.8 net) well suspended. The suspended well will be completed and tested during the first quarter of 2007.

As at December 31, 2006, McDaniel estimated total proved and probable reserves in this area to be 30.3 mbbls of crude, 630 mmcf of natural gas and 2.1 mbbls of NGL.

Annualized production from the Robin area averaged 1 bbl/d (2005 1 bbl/d) of NGL and 266 mcf/d (2005 - 407 mcf/d) of natural gas for the year ended December 31, 2006.

North Peace River Arch area, Alberta

The North Peace River Arch area is located west of the town of Peace River. Early in 2005 Masters successfully drilled two (1.0 net) gas wells in this area. Commencing in June 2005, Masters made several acquisitions for a total of $7.8 million and created a second core producing area. The acquisitions provided 160 boe/d of production (approximately 95 percent natural gas), 10,600 net undeveloped acres, ownership in several strategic field facilities and a large seismic data base associated with the properties.

In addition to the 2005 acquisitions, the Company drilled a total of six wells, four of which were natural gas wells, recompleted another six wells, acquired 10,528 net undeveloped acres, expanded existing production facilities and completed several large 3D seismic programs. At the end of 2005 and early in 2006 Masters shot an additional 240 square kilometers of 3D seismic.

In 2006 Masters drilled 21 wells at depths ranging from 400 to 1,600 meters resulting in 16 natural gas wells and one water injection well for a success rate of 76 percent. Generally the prospective wells target the Montney, Gething, Cadomin, Charlie Lake, Bluesky, Dunvegan, Paddy and Spirit River zones for oil and natural gas. The successful wells were tied into Company-owned facilities connected to the TCPL natural gas transmission system and brought on-stream during the fourth quarter of 2006 and first quarter 2007. TCPL has provided Masters with firm transportation service of 4.4 mmcf/d for a period of one to five years.

For 2007, Masters plans to drill six to 10 multi-zone exploration and development wells in the Peace River Arch core area.

Masters has an average working interest of 24 percent in 41,039 (9,781 net) acres of developed land and an average working interest of 31 percent in 93,804 (29,187 net) acres of undeveloped lands. As at December 31, 2006, 33 (9.1 net) wells were producing.

As at December 31, 2006, McDaniel estimated total proved and probable reserves to be 30.5 mbbls of crude oil and 6,240 mmcf of natural gas. Production averaged 9 bbls/d (2005 - 3 bbls/d) of crude oil and 1,916 mcf/d (2005 - 809 mcf/d) of natural gas for the year ended December 31, 2006.

Other properties and projects

Firebird, Alberta

The Firebird area is located approximately 150 miles north of the town of Slave Lake. Masters has a 100 percent working interest in 160 acres of developed land and one (1.0 net) shut-in natural gas well in this area.

As at December 31, 2006, McDaniel estimated total proved and probable reserves in this area to be 950 mmcf of natural gas and 1 mbbls of crude oil and NGL.

The Firebird area did not have any production for the year ended December 31, 2006. The well produced from May through September of 2003, when it was shut-in awaiting throughput capacity at a third party processing facility. Masters expects production to recommence in mid-2007.

Other properties

The Corporation has additional minor producing properties in the Brazeau, Edson, Figure Lake, Grand Forks, Queenstown and Roche Miette areas of Alberta.

Oil and gas wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2006:

	Oil				Natural gas			
	Producing		Non-producing		Producing		Non-producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	46	31.9	70	36.3	61	26.6	69	32.1
Total	46	31.9	70	36.3	61	26.6	69	32.1

Properties with no attributable reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2006.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta - Northern	58,399	17,256	170,812	63,373	229,211	80,629
Alberta - Southern	26,178	17,825	24,546	18,179	50,724	36,004
Total	84,577	35,081	195,358	81,552	279,935	116,633

The Corporation expects that rights to explore, develop and exploit 22,803 net acres of its undeveloped land holdings will expire by December 31, 2007.

Forward contracts

Masters sells crude oil to major crude oil aggregators under short-term floating price crude oil sales contracts, with the majority of production pipeline-connected. Masters' natural gas production is sold to natural gas aggregators at spot market prices.

Masters has arranged the following hedge contract for 2007.

Product	Index	Term	Daily notional volume	Price received
Gas fixed	AECO-C	Apr. 1/07 - Oct. 31/07	1,500 GJ	$7.54 per GJ

Additional information concerning abandonment and reclamation costs

The Corporation estimates the costs associated with abandonment and reclamation costs for surface leases, wells and facilities through its previous experience, where available, or by estimating such costs. The Corporation expects to incur abandonment and reclamation costs on 259 gross wells (137.2 net wells) including currently producing, non-producing wells and service wells as indicated below.

	Constant pricing		Forecast pricing		Forecast pricing	
	Proved NPV 0%	Proved NPV 10%	Proved NPV 0%	Proved NPV 10%	Proved plus probable NPV 0%	Proved plus probable NPV 10%
($ thousands)						
Associated with producing wells	2,074	847	2,876	1,061	2,876	914
Associated with non-producing, shut-in or no assigned reserves to wells	1,221	498	1,402	517	1,657	527
Total	3,295	1,345	4,278	1,578	4,533	1,441
Portion forecasted to be paid in next 3 years	500	402	528	425	512	413

Tax horizon

The income taxes deducted in the calculation of future net revenue above assumes a blow down scenario whereby the Corporation produces out its existing reserves. Under this scenario the Corporation is taxable in 2007. The Corporation forecasts its tax horizon assuming a continuing business model whereby it reinvests cash flow at historic capital efficiencies in order to achieve minimum production and reserves growth. Under this scenario the Corporation does not forecast being in a taxable position in 2007. The results are dependent upon commodity prices and capital spending levels.

Capital expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2006.

($ thousands)	
Property acquisition costs - unproved properties	1,669
Property disposition costs - proved properties	(6,200)
Exploration costs	13,890
Development costs	8,930
Total	18,289

Exploration and development activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2006.

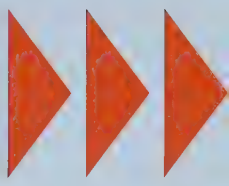
(wells)	Gross	Net
Light and medium oil	-	-
Natural gas	17	7.0
Dry	14	7.1
Total	31	14.1

For details on the most important current and likely exploration and development activities during 2006, see "Principal Properties".

Production estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2007, which is reflected in the estimate of proved reserves future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Light and medium oil (bbls/d)	Natural gas (mcf/d)	Natural gas liquids (bbls/d)	Total production (boe/d)
2007	840	6,240	11	1,891



MANAGEMENT'S DISCUSSION AND ANALYSIS

Production history

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and the resulting netback for the periods indicated below.

	Quarter ended 2006			
	Dec 31	Sep 30	Jun 30	Mar 31
Average daily production [1]				
Light and medium crude oil *(bbls/d)*	749	791	781	813
Natural gas *(mcf/d)*	4,417	2,897	3,543	3,888
NGL *(bbls/d)*	10	10	13	9
Total *(boe/d)*	1,495	1,284	1,384	1,470
Average price received				
Light and medium crude oil *($/bbl)*	42.31	58.03	59.65	39.82
Natural gas *($/mcf)*	7.07	5.61	5.91	7.41
NGL *($/bbl)*	71.65	62.71	61.62	56.87
Combined *($/boe)*	42.57	48.92	49.34	41.97
Royalties paid				
Light and medium crude oil *($/bbl)*	7.96	9.52	11.00	7.88
Natural gas *($/mcf)*	1.57	0.30	1.53	1.80
NGL *($/bbl)*	23.70	21.48	19.91	22.87
Combined *($/boe)*	8.60	6.15	10.38	9.12
Operating expenses [2]				
Light and medium crude oil *($/bbl)*	10.23	10.65	9.34	6.70
Natural gas *($/mcf)*	2.80	2.58	1.26	2.10
NGL *($/bbl)*	-	-	-	-
Combined *($/boe)*	13.39	12.38	8.49	9.26
Netback received [2]				
Light and medium crude oil *($/bbl)*	24.12	37.86	39.31	25.24
Natural gas *($/mcf)*	2.70	2.73	3.12	3.51
NGL *($/bbl)*	47.95	41.23	41.71	34.00
Total *($/boe)*	20.58	30.39	30.47	23.59

Notes:
(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues. Operating costs have not been allocated to the natural gas liquids netback presented but are borne by the primary product, natural gas.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2006.

	Light and medium crude oil	Natural gas	NGL	Total
	(bbls/d)	*(mcf/d)*	*(bbls/d)*	*(boe/d)*
Little Bow	696	219	1	734
Badger	-	394	3	68
Eyremore	-	553	2	95
Long Coulee	39	13	-	41
North Peace River Arch	9	1,916	-	328
Robin	-	266	1	45
Other	40	324	3	97
Total Alberta	784	3,685	10	1,408

For the twelve months ended December 31, 2006, approximately 60 percent of Masters gross resource revenue was derived from crude oil production and 40 percent was derived from natural gas production (including by-products).

Marketing

Masters sells crude oil to major crude oil aggregators under short-term floating price crude oil sales contracts, with the majority of production pipeline-connected. Masters natural gas production is sold to natural gas aggregators at spot market prices. Masters has arranged the following hedge contract for 2007.

Product	Index	Term	Daily notional volume	Price received
Gas fixed	AECO-C	Apr. 1/07 - Oct. 31/07	1,500 GJ	$7.54 per GJ

MANAGEMENT'S REPORT

All of the information in Masters Energy Inc.'s annual report is the responsibility of management and has been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect management's best judgments. Management has determined such amounts on a reasonable basis to ensure fair presentation of the financial statements in all material respects. Management has reviewed the financial information throughout the annual report to ensure consistency in all material respects with that in the financial statements.

The Company maintains appropriate systems of internal control to provide reasonable assurance that transactions are authorized to safeguard assets from loss or unauthorized use and to produce reliable and accurate financial records for the preparation of financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board exercises this responsibility through the Audit Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation.

The Audit Committee, composed entirely of independent Directors, meets at least on a quarterly basis with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the financial statements and Management' s Discussion and Analysis before presentation to the Board of Directors for approval. On the recommendation of the Audit Committee, the financial statements and Management's Discussion and Analysis received the approval of the Board of Directors. The Audit Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

KPMG LLP, an independent firm of chartered accountants, has been appointed by a vote of shareholders at the Company's last annual meeting to audit the financial statements in accordance with Canadian generally accepted auditing standards and to provide their auditors' report. Their report is presented with the financial statements. KPMG LLP has full and free access to the Audit Committee.

Geoff C. Merritt
President and Chief Executive Officer
March 9, 2007

Randall P. Boyd
Chief Financial Officer

AUDITORS' REPORT

o the Shareholders of Masters Energy Inc.

We have audited the balance sheets of Masters Energy Inc. as at December 31, 2006 and 2005 and the statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on those financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PMG LLP

Accountants
Canada
07

BALANCE SHEETS

As at December 31, ($ thousands)		2006		2005
Assets				
Current assets				
Accounts receivable	$	4,283	$	3,608
Prepaid expenses and deposits		281		190
		4,564		3,798
Property and equipment *(note 2)*		65,711		56,218
	$	70,275	$	60,016
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	$	6,720	$	8,811
Long-term bank debt *(note 3)*		17,824		14,093
Asset retirement obligations *(note 4)*		3,527		3,316
Future income taxes *(note 8)*		2,283		2,005
		30,354		28,225
Shareholders' equity				
Share capital *(note 5)*		33,314		27,469
Contributed surplus *(note 6)*		820		393
Retained earnings		5,787		3,929
		39,921		31,791
Commitments *(notes 5 and 9)*				
Subsequent events *(note 5)*				
	$	70,275	$	60,016

See accompanying notes to the financial statements.

Approved on behalf of the Board,

William R. Stedman, *Director*

Douglas H. Mitchell, *Director*

STATEMENTS OF EARNINGS AND RETAINED EARNINGS

For the years ended December 31, *(thousands except share and per share amounts)*	2006	2005
Revenue		
Petroleum and natural gas revenue	$ 23,405	$ 22,216
Royalty and other revenue	859	713
	24,264	22,929
Royalties, net of Alberta Royalty Tax Credit	(4,394)	(4,695)
	19,870	18,234
Unrealized gain on commodity contract *(note 10)*	325	-
	20,195	18,234
Expenses		
Operating	5,600	4,168
General and administrative	1,989	1,436
Interest - long-term debt	1,014	322
- short-term debt	-	92
Depletion, depreciation and accretion	9,400	6,627
	18,003	12,645
Earnings before taxes	2,192	5,589
Taxes *(note 8)*		
Capital	-	3
Future	334	1,975
	334	1,978
Net earnings	1,858	3,611
Retained earnings, beginning of year	3,929	318
Retained earnings, end of year	$ 5,787	$ 3,929
Earnings per share *(note 7)*		
Basic	$ 0.12	$ 0.25
Diluted	$ 0.12	$ 0.24
Weighted average number of shares outstanding *(note 7)*		
Basic	15,255,640	14,420,197
Diluted	15,887,870	15,090,130

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

For the years ended December 31, ($ thousands)	2006	2005
Cash provided by (used for):		
Operating activities		
Net earnings	$ 1,858	$ 3,611
Add (deduct) non-cash items		
Depletion, depreciation and accretion	9,400	6,627
Future income tax expense	334	1,975
Stock-based compensation expense	322	227
Unrealized gain on commodity contract	(325)	-
Settlement of performance warrants	(52)	-
Settlement of asset retirement costs	(98)	(281)
	11,439	12,159
Changes in non-cash working capital	(1,865)	3,087
	9,574	15,246
Financing activities		
Increase in bank debt	3,731	10,669
Proceeds on share issuance	6,100	-
Proceeds on exercise of options and warrants	99	383
Purchase of shares for cancellation	(102)	-
Share issuance costs	(446)	-
	9,382	11,052
Investing activities		
Petroleum and natural gas properties		
Exploration and development	(24,489)	(20,289)
Producing property acquisitions	-	(7,844)
Disposal of property	6,200	600
	(18,289)	(27,533)
Changes in non-cash working capital	(667)	1,235
	(18,956)	(26,298)
Change in cash and cash equivalents	-	-
Cash and cash equivalents, beginning of year	-	-
Cash and cash equivalents, end of year	$ -	$ -
Supplemental cash flow information		
Interest income received	$ 1	$ 6
Interest paid	$ 1,014	$ 470
Capital taxes paid	$ 3	$ -

See accompanying notes to the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2006 and 2005

(Tabular amounts in $ thousands except share and per share amounts)

Description of business

Masters Energy Inc. ("Masters" or the "Company") is engaged in the exploration, development and production of petroleum and natural gas in western Canada.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation

These financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(b) Cash and cash equivalents

Cash and cash equivalents consisted of amounts on deposit with banks and term deposits with original maturities of less than 90 days.

(c) Property and equipment

The Company follows the full cost method for accounting for petroleum and natural gas operations whereby all costs related to the acquisition of and the development of petroleum and natural gas reserves are capitalized. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and production and well equipment.

Costs capitalized together with future capital costs are depleted and depreciated using the unit-of-production method based upon gross proved petroleum and natural gas reserves as determined by independent qualified reserves evaluators at future prices and costs. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content, where one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The cost of significant unproved properties is excluded from the depletion and depreciation base until it is determined whether proved reserves are attributable to the properties, or impairment has occurred.

The Company performs a ceiling test for impairment for each cost centre in a two-stage test undertaken at least annually.

(i) Impairment is recognized if the carrying value of the petroleum and natural gas properties, less accumulated depletion and depreciation, exceeds the estimated future cash flows from proved oil and natural gas reserves, on an undiscounted basis, using forecast prices and costs and the lower of cost and fair value of unproven properties. Future cash flows are calculated before interest, general and administrative expenses and income taxes.

(ii) If impairment is indicated by applying the calculations described in (i) above, the Company will measure the amount of the impairment by comparing the carrying value of the petroleum and natural gas properties less accumulated depletion and depreciation to the estimated future cash flows from the proved and probable oil and natural gas reserves, discounted at a risk-free rate of interest, using forecast prices and costs and the lower of cost and fair value of unproven properties. Any impairment recognized is recorded as additional depletion and depreciation expense.

NOTES TO THE FINANCIAL STATEMENTS

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion and depreciation by 20 percent or more.

The costs of office equipment are amortized at rates approximating their useful lives on a declining balance basis of 30 percent per year.

(d) Joint operations

Substantially all of the Company's exploration and production activities are conducted jointly with others and, accordingly, these financial statements reflect only the Company's interest in such activities.

(e) Asset retirement obligations

The Company recognizes the liability for retirement obligations associated with the abandonment of petroleum and natural gas wells, related facilities, compressors and plants, removal of equipment from leased acreage and returning such land to its original condition. The fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Company's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by Company management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related oil and natural gas properties, and a corresponding liability is recognized. This component of the increase in petroleum and natural gas properties is depleted and depreciated on the same basis as the remainder of the petroleum and natural gas properties. The liability is adjusted for accretion charged to income until the obligation is settled or sold and for revisions to the estimated cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

(f) Flow-through shares

From time to time, the Company issues flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, share capital is reduced and a future income tax liability is recorded equal to the estimated amount of future income taxes payable by the Company as a result of the renunciations, when the expenditures are renounced.

(g) Stock-based compensation

The Company issues stock options and performance warrants to directors, officers and employees as described in note 6. Compensation cost, attributable to stock options and performance warrants granted, is measured by the fair value method of accounting at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. When stock options or performance warrants are exercised, the cash proceeds, together with the amount previously recorded as contributed surplus are recorded as share capital. The Company incorporates an estimated forfeiture rate of ten percent for stock options and performance warrants that will not vest.

(h) Revenue recognition and operating expenses

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(i) Income taxes

Future income taxes are accounted for using the liability method of income tax allocation. Under the liability method, estimated future tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities. Future income tax assets and liabilities are determined based on the income tax laws and rates that are anticipated to apply in the period of reversal. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(j) Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. The Company utilizes the treasury stock method for the calculation of diluted per share amounts. This method assumes that the proceeds from the exercise of in-the-money stock options and warrants plus the unamortized stock-based compensation are used to repurchase Company shares at the weighted average market price during the period.

(k) Measurement uncertainty

The amounts recorded for depletion and depreciation of oil and gas properties, the asset retirement obligation and the ceiling test are based on estimates. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions.

The amounts disclosed relating to the fair value of stock options and performance warrants issued and the resulting income impact are based on estimates of the future volatility of the Company's share price, expected lives of the options, expected dividends and other relevant assumptions.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

(l) Derivative financial instruments

Derivative financial instruments are used by Masters to manage economic exposure to market risks relating to commodity prices. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

Financial contracts are recorded following the fair value method whereby instruments are recorded in the balance sheet as either as asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to commodity prices are recognized in natural gas and crude revenues as related sales occur. Unrealized gains or losses are recognized in revenues at the end of each respective reporting period. The estimated fair value of derivative instruments is based on quoted market prices.

NOTES TO THE FINANCIAL STATEMENTS

2. PROPERTY AND EQUIPMENT

As at December 31, 2006	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties and well equipment	$ 85,756	$ 20,080	$ 65,676
Office equipment	73	38	35
	$ 85,829	$ 20,118	$ 65,711
As at December 31, 2005			
Petroleum and natural gas properties and well equipment	$ 66,992	$ 10,820	$ 56,172
Office equipment	73	27	46
	$ 67,065	$ 10,847	$ 56,218

The value of undeveloped lands excluded from costs subject to depletion was $7.6 million at December 31, 2006 (December 31, 2005 - $8.7 million).

As at December 31, 2006, $1.0 (December 31, 2005 - $0.6) million of general and administrative costs were capitalized.

The benchmark and Company prices on which the December 31, 2006 ceiling test for impairment is based, are as follows.

	Oil		Natural gas		Natural gas liquids	
	Bow River medium benchmark	Company	AECO spot benchmark	Company	Edmonton benchmark	Company
	($/bbl)	($/bbl)	($/GJ)	($/mcf)	($/bbl)	($/bbl)
2007	49.30	48.84	6.85	7.07	50.80	62.90
2008	49.60	48.68	7.05	7.33	50.10	62.99
2009	49.80	48.46	7.40	7.68	49.50	61.48
2010	49.30	47.58	7.50	7.98	48.60	64.08
2011	47.90	46.03	7.70	8.18	47.60	61.56

Prices increase at a rate of approximately 2.0 percent per year for oil, natural gas and natural gas liquids after 2011. Adjustments were made to the benchmark prices, for purposes of the ceiling test, to reflect varied delivery points and quality differentials in the products delivered.

3. LONG-TERM DEBT

The Company has access to a revolving term credit facility with a Canadian chartered bank to a maximum of $22.0 million. The credit facility may be drawn with advances or bankers' acceptances or repaid. Direct advances bear interest at the bank's prime lending rate and the bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a stamping fee. The revolving term credit facility is available for a period of 364 days until April 30, 2007. Up to 60 days prior to April 30, 2007 the Company may request an extension of the revolving facility for a period of another 364 days, subject to the bank's approval. If the Company does not request the extension or the bank does not agree to the extension, the credit facility principal borrowed will be repaid in full with a single payment 366 days subsequent to April 30, 2007. The nature of the lending facility is such that it is recognized as a long-term liability. In the event that the facility was not reviewed on April 30, 2007 the entire amount would be repayable on May 1, 2008.

As of December 31, 2006, $17.8 million (December 31, 2005 - $14.1 million) has been drawn against the revolving term credit facility.

The Company has available a $2.5(US) million demand swap facility, to assist in financing the contingent exposure of settlement for financial commodity swaps. The facility bears interest at a US base rate per annum on amounts drawn. No amount has been drawn at December 31, 2006.

Security pledged for the facilities consists of a general assignment of book debts, a $40.0 million demand debenture, secured by a first floating charge over all the assets of the Company. The Company is not in breach of any covenants under its credit facility.

4. ASSET RETIREMENT OBLIGATIONS

The following table summarizes changes in the asset retirement obligations for the years ended December 31, as indicated.

		2006		2005
Asset retirement obligations, beginning of year	$	3,316	$	3,044
Adjustments		(122)		(256)
Liabilities acquired		-		305
Liabilities incurred		301		390
Settlement of asset retirement costs		(98)		(281)
Accretion expense		130		114
Asset retirement obligations, end of year	$	3,527	$	3,316

The total estimated, undiscounted cash flows required to settle the obligations as at December 31, 2006, before considering salvage, is $4.9 (2005 - $4.6) million which has been discounted using a weighted average credit-adjusted risk-free interest rate of 6.0 percent. The Company expects these obligations to be settled in approximately 1 to 14 years.

5. SHARE CAPITAL

(a) Authorized

Unlimited number of voting common shares, without nominal or par value
Unlimited number of preferred shares, issuable in series, with rights and privileges to be determined at the time of issuance by the Board of Directors

(b) Issued

	Number		Amount
Common shares, December 31, 2004	14,363,647	$	27,042
Exercise of stock options and performance warrants	159,666		383
Transfer from contributed surplus for exercise of options and warrants	-		44
Common shares, December 31, 2005	14,523,313		27,469
Issue of flow-through shares	1,000,000		6,100
Exercise of stock options	46,666		99
Shares repurchased and cancelled	(30,000)		(67)
Share issue costs (net of future tax benefit of $140,000)	-		(306)
Transfer from contributed surplus for exercise of options and warrants	-		19
Common shares, December 31, 2006	**15,539,979**	**$**	**33,314**

NOTES TO THE FINANCIAL STATEMENTS

(c) On April 18, 2006 the Company issued, through a private placement, 1,000,000 common shares on a "flow-through" basis at a price of $6.10 per share for net proceeds (after share issue costs of $434,000) of $5,666,000. The Company is obligated to incur $6.1 million of qualifying expenditures prior to December 31, 2007. As at December 31, 2006, the remaining obligation was approximately $0.8 million.

(d) In November 2006, the Company received regulatory approval under the Canadian securities laws to purchase and cancel up to 1,300,000 common shares under a normal course issuer bid. The issuer bid will terminate on November 6, 2007. During 2006, the Company purchased 30,000 common shares for total consideration of $102,000. Of the amount paid, $67,000 was charged to share capital and $35,000 was charged to contributed surplus. Subsequent to the 2006 year-end, the Company has purchased 70,000 common shares under the issuer bid for total consideration of $202,400

6. STOCK-BASED COMPENSATION PLANS

The Company's stock-based compensation plans are described below:

(a) Stock options

The Company's stock option plan allows for options to be granted to employees, officers, directors and other service providers. The number of shares which may be issued, and that have been reserved, under the plan is limited to 10 percent of the issued and outstanding common shares. The maximum number of shares that may be reserved for issuance to any one person under the plan is limited to five percent per year of the issued and outstanding Common Shares and Special Warrants for employees, officers and directors and two percent for other service providers. The plan also provides that the price at which options may be granted cannot be less than the volume weighted average trading price of the common shares for the five trading days prior to the date of grant. Options granted under the plan have a maximum life of five years and vest at an equal amount over three years on the anniversary date of the grant or as determined by the Board of Directors.

The following tables summarizes information about the Company's stock options outstanding at December 31, 2006.

	Number of options	Weighted average exercise price ($)
Balance, December 31, 2004	1,255,000	2.19
Granted	50,000	3.80
Cancelled	(83,334)	2.14
Exercised	(94,666)	2.09
Balance, December 31, 2005	1,127,000	2.28
Granted	404,000	4.62
Cancelled	(33,334)	2.09
Exercised	(46,666)	2.12
Balance, December 31, 2006	**1,451,000**	**2.94**

As of December 31, 2006, 814,665 stock options (2005 - 490,320) have vested at an average exercise price of $2.21 per option (2005 - $2.11).

Exercise price per share ($)	Options outstanding	Weighted average years to expiry
2.00	400,000	2.0
2.35	572,000	2.3
2.60	25,000	3.0
3.80	50,000	3.5
4.70	150,000	4.3
4.58	254,000	4.4
Weighted average 2.94	1,451,000	2.8

The Company has recorded compensation expense of $0.3 million as at December 31, 2006, (2005 - $0.2 million) for options and warrants vested during the period. Using the Black-Scholes model, assuming the expected life of the options and warrants are five years and no expected future dividends, the following table summarizes the total fair value of options and warrants granted.

Grant date	Options and warrants granted	Expected volatility (%)	Risk-free interest rate (%)	Total fair value ($ thousands)
May 11, 2006	319,000	44	4.0	577
April 10, 2006	150,000	42	3.7	266
July 26, 2005	50,000	46	3.8	78
December 23, 2004	25,000	33	3.4	21
April 26, 2004	655,000	26	3.4	455

(b) Performance warrants

The Company's Performance Warrants Plan allows for Performance Warrants to be granted to employees, officers and directors. The maximum number of shares which may be issued, and that have been reserved, under the plan is 1,000,000 common shares. Performance Warrants granted under the plan have a five year life, vest immediately and have no performance criteria other than the escalating exercise price. As at December 31, 2006, 885,000 (2005 - 870,000) Performance Warrants have been granted, expiring December 22, 2008, with the following exercise prices.

	Performance warrants outstanding and exercisable	Weighted average exercise price per warrant ($)
Balance, December 31, 2004	1,000,000	3.55
Exercised	(65,000)	2.85
Unallocated	(65,000)	-
Balance, December 31, 2005	870,000	3.55
Granted	65,000	4.58
Settled	(50,000)	3.66
Balance, December 31, 2006	**885,000**	**3.62**

NOTES TO THE FINANCIAL STATEMENTS

(c) Contributed surplus

The following table reconciles the Company's contributed surplus for the years ended December 31, as indicated.

		2006		2005
Balance, beginning of year	$	393	$	210
Stock-based compensation expense		322		227
Capitalized stock-based compensation		211		-
Exercise of options and performance warrants		(19)		(44)
Settlement of performance warrants		(52)		-
Reacquisition and cancellation of common shares		(35)		-
Balance, end of year	$	820	$	393

7. PER SHARE AMOUNTS

Earnings per share has been calculated using the basic weighted average number of common shares outstanding of 15,255,640 (2005 - 14,420,197) during the year ended December 31, 2006. As at December 31, 2006, a total of 632,230 (2005 - 669,933) were added to the total to take into account the dilutive effect of the options for the year.

8. INCOME TAXES

(a) The provision for income tax expense differs from that which would be expected from applying the combined effective Canadian federal and provincial income tax rate of 34.5 percent (2005 - 37.62 percent) to income before income taxes. The difference results from the following:

		2006		2005
Expected income tax expense	$	756	$	2,103
Increase (decrease) resulting from:				
Non-deductible crown payments		469		928
Resource allowance		(402)		(907)
Effect of change in income tax enacted		(461)		-
Stock-based compensation expense		111		85
Other		(139)		(234)
Capital tax		-		3
Tax expense	$	334	$	1,978

(b) The components of the future income tax liability at December 31 are as follows:

		2006		2005
Carrying value of property and equipment in excess of available tax deductions	$	3,718	$	3,582
Asset retirement obligation		(1,036)		(1,076)
Share issuance costs		(227)		(286)
Attributed Canadian Royalty Income		(172)		(215)
	$	2,283	$	2,005

As at December 31, 2006, the Company has income tax pools of approximately $49.0 million (2005 - $46.6 million) available for deduction against future taxable income.

9. COMMITMENTS

The table below shows commitments due within the periods indicated.

	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Farm-in commitments	$ 620	$ 620	$ -	$ -	$ -
Firm transportation commitments	1,340	334	504	430	72
Operating leases	114	114	-	-	-
Office lease	331	87	244	-	-
Total contractual obligations	$ 2,405	$ 1,155	$ 748	$ 430	$ 72

10. FINANCIAL INSTRUMENTS

(a) Derivative instruments

The Company has a price risk management program whereby the commodity price associated with a portion of its future production can be fixed. The Company is able to sell forward a portion of its future production through a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward and future contracts are subject to market risk from fluctuating commodity prices and exchange rates; however, gains or losses on the contracts are offset by changes in the value of the Company's production and recognized in income in the same period and category as the hedged item.

The Company uses derivative instruments to reduce its exposure to fluctuations in commodity prices. The following table summarizes the derivative contract in place at December 31, 2006:

Product	Index	Term	Daily notional volume	Price received	Unrealized gain ($ thousands)
Gas fixed	AECO-C	Apr. 1/07 - Oct. 31/07	1,500 GJ	$7.54 per GJ	325

(b) Fair values

The fair values of the Company's accounts receivable, accounts payable and accrued liabilities approximate their carrying values due to their short-term maturity. The Company's long-term debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

(c) Credit risk

The Company's credit risk is limited to the carrying amount of its accounts receivable, which are due primarily from other entities involved in the oil and gas industry. These amounts are subject to the same risks as the industry as a whole.

(d) Interest rate risk

The Company is exposed to interest rate risk to the extent the changes in market interest rates will impact the Company's debts that have a floating interest rate.

CORPORATE INFORMATION

DIRECTORS

Fred Coles [1] [3]
Calgary, Alberta
President, Menehune Resources Ltd.

Kerry Lyons [3]
DeWinton, Alberta
President and CEO, Greenfield Resources Ltd.

Geoffrey C. Merritt [2]
Calgary, Alberta
President and CEO, Masters Energy Inc.

Douglas H. Mitchell [2]
Calgary, Alberta
Co-Chairman and Managing Partner, Borden Ladner Gervais LLP

John W. (Jack) Peltier [1] [2]
Calgary, Alberta
President, Ipperwash Resources Ltd.

William R. Stedman [1] [3]
Calgary, Alberta
Chairman and CEO, ENTx Capital Corporation

[1] *Member of Audit Committee*
[2] *Member of Compensation Committee*
[3] *Member of Reserves Committee*

OFFICERS

Geoffrey C. Merritt
President and CEO

Randall P. Boyd
Chief Financial Officer

Peter Lundberg
Vice President, Engineering

INDEPENDENT QUALIFIED RESERVES EVALUATORS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Borden Ladner Gervais LLP
Calgary, Alberta

STOCK EXCHANGE AND LISTING

Toronto Stock Exchange "TSX"
Trading Symbol "MSY"

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company
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ANNUAL MEETING OF SHAREHOLDERS

The Calgary Telus Convention Centre
Exhibition Hall B1, 120 - 9 Avenue SE
Calgary, Alberta
Wednesday, May 9, 2007 at 2:00 pm (Calgary time)

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